Section 1: Past and Present Trends in Washington's Natural Gas Market

Introduction

This report updates the 2001 natural gas study, *Convergence: Natural Gas and Electricity in Washington,* to reflect current market conditions, identifies important natural gas supply and market issues, and considers the implications for consumers and energy policy in Washington State.

Background

The Pacific Northwest is served by two major natural gas pipelines (Figure 1.1). The Northwest Pipeline, owned and operated by the Williams Company, was constructed in the late 1950s and reaches most urban locations in the state. The Pacific Gas & Electric Gas Transmission Northwest (PG&E GTN) pipeline (frequently referred to as "PGT," after the previous name, "Pacific Gas Transmission") went into service in 1961 primarily to serve customers in California, but now also serves as an important source of supply for the region.

The Northwest Pipeline connects the Pacific Northwest to natural gas fields in the Rocky Mountains region and in British Columbia and Alberta, Canada. The Northwest Pipeline interconnects with the facilities of both Westcoast Energy, Inc. and Sumas International Pipeline, Inc. at the Canadian border near Sumas, Washington, and it connects with El Paso Natural Gas Company, Transwestern Pipeline Company, Colorado Interstate Gas Company, Questar Pipeline Company, Kern River Gas Transmission Company, and Paiute Pipeline Company at various points in New Mexico, Colorado, Wyoming and Nevada.

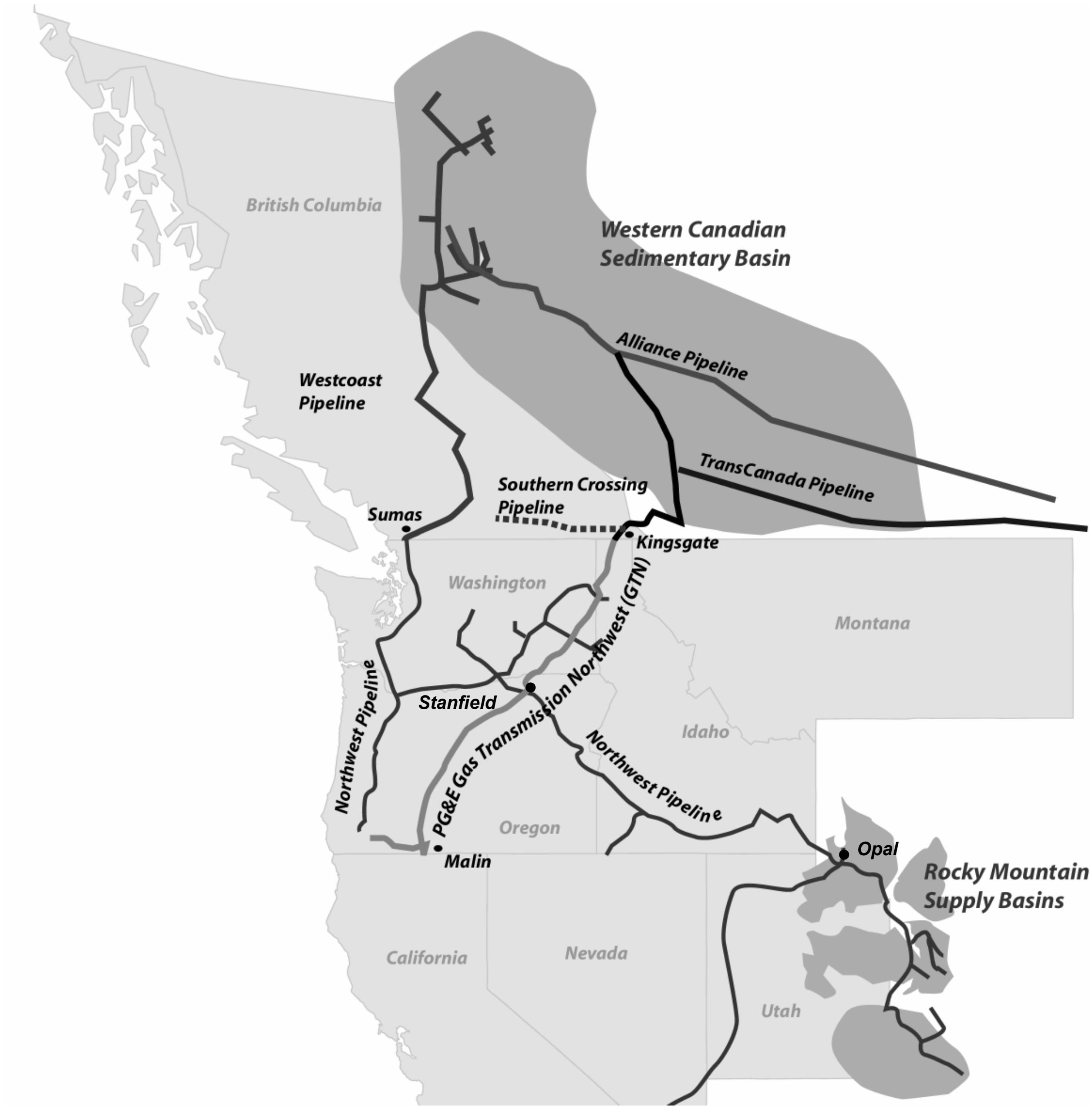

Figure 1.1. Major Natural Gas Pipelines Serving the Northwest

The GTN pipeline was constructed primarily to connect California to natural gas supplies in Alberta, Canada. But it also serves customers in the Pacific Northwest (Avista Utilities and Cascade Natural Gas) and connects to the Northwest Pipeline at Stanfield, Oregon, and Spokane and Palouse, Washington. The GTN pipeline interconnects with TransCanada at Kingsgate, British Columbia, and Pacific Gas and Electric Company and Tuscarora Gas Transmission Company at Malin, Oregon. GTN also delivers to power plants at Coyote Springs and Hermiston, Oregon.

In addition to flowing gas from pipelines, Washington State's gas utilities rely on underground storage fields to meet peak demands. The location of major storage facilities close to end-use customers allows storage to substitute for pipeline capacity in meeting peak demand days. The largest, Jackson Prairie near Chehalis, Washington, with18,300 MDth[1] working gas capacity, is owned by Avista Corporation, Puget Sound Energy and Northwest Pipeline in equal shares. The Mist, Oregon, storage facility is owned by Northwest Natural. In addition, Questar has a storage facility at Clay Basin in Northeast Utah in which Puget Sound Energy, Northwest Pipeline and other regional shippers hold capacity. These facilities are primarily used for seasonal storage to increase peak day deliverability. Gas is injected during off-peak periods and retrieved during the peak winter heating season. Refill begins in spring and continues through September, when 90-100 percent of capacity is usually achieved. As much as half of the gas consumed on a cold winter day comes from storage fields.

Within local communities, gas is distributed by four investor-owned utilities (Puget Sound Energy, Avista, Cascade Natural Gas and Northwest Natural Gas), sometimes called local distribution companies (LDCs), and three small city-owned utilities (Ellensburg, Enumclaw and Buckley). This contrasts with electric utility customers where just under half are served by regulated investor-owned utilities and the remainder by public utilities. The gas utilities purchase gas at market hubs,[2] and transport the gas through the interstate pipeline system to the "city gate" where it enters the local distribution system. The Washington Utilities and Transportation Commission (UTC) regulates local distribution company gas retail rates. Service territories of the four major LDCs within Washington State are depicted in Figure 1.2. Many large customers arrange for their own gas supplies from market hubs and purchase transportation services from interstate pipelines and/or LDCs.

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[1] Thousand decatherms (MDth). A decatherm is equal to a million British Thermal Units (Btu).

[2] Natural gas market hubs evolved from Federal Energy Regulatory Commission (FERC) gas industry restructuring orders in 1992. These market centers provide new gas shippers with many of the physical capabilities and administrative support services formerly handled by interstate pipeline companies "bundled" sales and services. Centers exist where two or more pipelines interconnect. The Sumas Center in British Columbia is the principal source for trading and transportation of natural gas in the Pacific Northwest. Other centers relevant to the region are at Kingsgate, Idaho; Malin and Stanfield, Oregon and the Opal Hub in Wyoming.

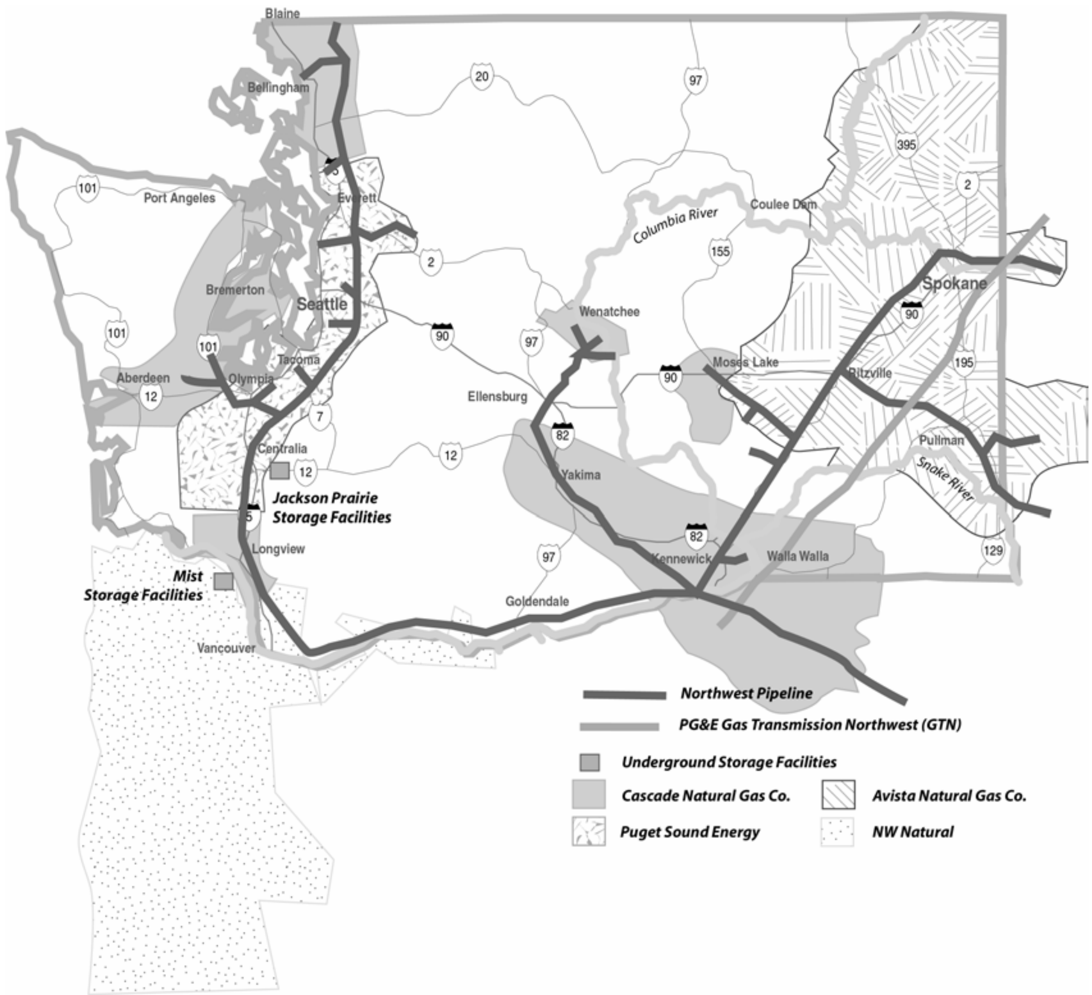

Figure 1.2. Natural Gas Utility Service Areas in Washington State

Past Trends and the Energy Crisis

The period leading up to the energy crisis of 2000 and 2001 can be characterized by a period of regulation prior to 1985, followed by a period of deregulation and industry restructuring.

Pre-1985: Regulation

During this period, the Federal Power Commission, now the Federal Energy Regulatory Commission (FERC), regulated the price of natural gas from the well to the pipeline, and the price charged by pipelines to deliver the gas to local gas utilities. State regulatory commissions regulated local gas utilities' prices to retail customers. Gas prices were regulated from the point of production to the point of use. Because prices were low, natural gas demand grew significantly until the early 1970s. A large share of natural gas production remained a by-product of oil well development, where profits were not regulated. But low prices and a maturing resource base meant that an insufficient number of new wells were being developed. By the early 1970s domestic gas supplies could not keep pace with growing demand.

This fact was very important to the evolution of the natural gas market in the state of Washington. The U.S. producers were subject to federal price controls, while the Canadian producers were not. As domestic supplies became limited and did not meet demand, Washington utilities turned to Canadian suppliers.

This had several impacts on the Northwest. First, the pipeline capacity from the Southwest was not expanded, since there was no additional marketable domestic gas available. Second, pipeline capacity to the Canadian border was expanded. As a result of having much of our demand met with un-regulated higher-cost Canadian gas, consumers in Washington State paid gas prices that were higher (more than $1/MMBtu in the early 1980s) than were paid in other parts of the United States. Higher than average gas prices, coupled with the lowest electric rates in the nation, meant that natural gas was slow to evolve as a residential and commercial heating fuel in the Pacific Northwest.

The Federal Power Commission began raising the regulated price of wellhead gas in the mid 1970s to provide incentive to bring production on line. Higher price limits and the shortages during 1972-77 caused some increase in drilling and stabilized productive capacity. Higher fuel prices combined with the recessions of the 1970s, and other factors, reduced demand for natural gas. The Natural Gas Policy Act (NGPA) of 1978 began the deregulation process. The newly authorized FERC allowed several more price increases during 1978-85 for regulated gas, which now also included intrastate gas. Gas wells that came into production after the NGPA of 1978 were not regulated, so the market was becoming a mixed regulated and open market. In addition, the high wellhead prices allowed by FERC were no longer constraining resource development. The deep recession of 1980-82 and high oil and gas prices resulted in demand destruction, and efficiency improvements. The outcome was that as supply was increasing, demand was falling rapidly, resulting in a drop in natural gas and oil prices in the mid 1980s.

It also should be noted that the Federal Power Plant and Industrial Fuel Use Act, passed by Congress in 1978, prohibited natural gas use in new electric utility generating facilities starting in 1980, except under specific exemptions such as peaking power plants. The intent of this prohibition was to conserve natural gas for uses other than the generation of electricity, encourage the use of coal or alternative fuels in the place of natural gas, and ensure natural gas availability for high priority purposes. The utility industry strongly opposed this provision because of the high cost of replacing natural gas generation. In 1981, when gas shortages disappeared and gas supplies increased, Congress repealed this prohibition as part of the Omnibus Budget Reconciliation Act Of 1981.

1985-1999: Natural Gas Industry Restructuring

During the 1980s, federal and state regulatory authorities significantly restructured the natural gas industry regulatory framework and decontrolled domestic gas prices in 1985. The federal action was directed at stimulating exploration and drilling, introducing additional competition into the industry, and increasing the utilization of the gas pipeline network. State action was largely a response to federal action.

A key change enacted by FERC was unbundling of pipeline service, separating the business of gas supply from the business of operating the pipeline. With the new structure, each of the local distribution companies in Washington State entered into direct contracts with gas producers and/or marketers for their gas supply and they purchased capacity from the pipeline companies to deliver the natural gas. Also industrial customers were allowed to become "transportation" customers, meaning they could buy directly from producers and pay the utility only for delivery services.

These changes in the market along with reductions in the cost to bring new supplies on line (due to improvements in seismology and drilling technology) led to increased supply, lower prices, and growth in demand.

Historical Natural Gas Prices and Demand

After peaking in the early 1980s, inflation adjusted retail natural gas prices had declined significantly by 1990, nearing price levels of the mid-1970s (Figure 1.3). Prices were relatively stable throughout the 1990s. Residential prices were highest and were almost twice as much as industrial rates for much of this period, largely due to the higher cost of delivering gas to smaller customers. Natural gas prices for utilities tended to be more volatile because consumption was primarily for natural gas-fired power plants used for meeting peak power demand, and was generally supplied under interruptible rate schedules. Thus consumption for electricity generation was modest (1 to 5 percent of total) and varied from year-to-year.

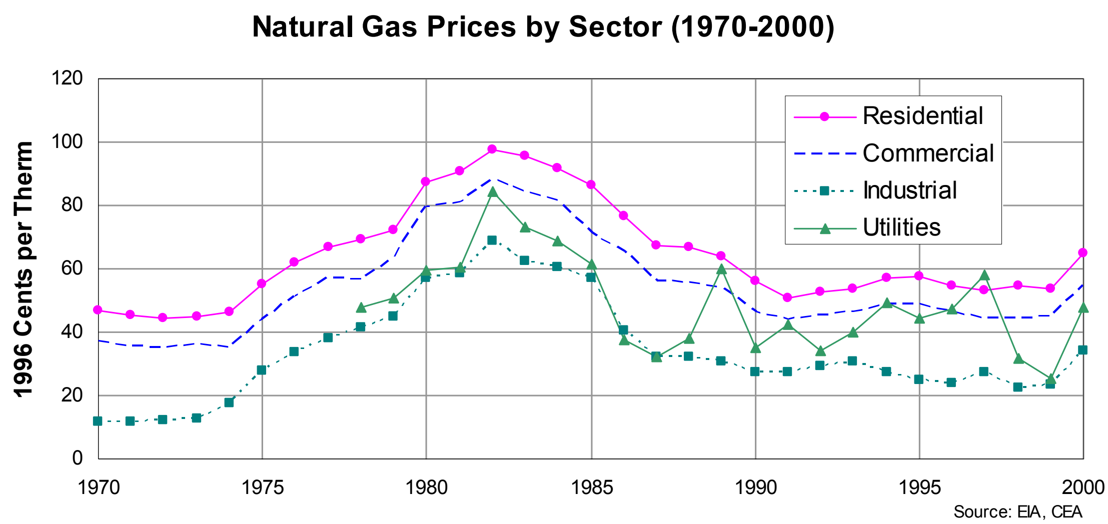

Figure 1.3. Historical Natural Gas Prices in Washington State

Natural gas consumption in Washington State grew through the early 1970s, declined through the early 1980s, and resumed its growth through most of the 1980s and 1990s (Figure 1.4). These trends reflect the supply and price situation during these periods. Total statewide natural gas consumption in 1999 was about a third more than the previous consumption peak in 1973.

Residential and commercial consumption was relatively stable through much of this period, showing modest declines in the late 1970s and growth in the 1990s. Increasing demand in these sectors was due to growth in the population and the economy as well as an increasing preference for natural gas for heating, water heating and industrial processes. This was partly due to higher electricity prices and lower natural gas prices improving the relative advantage of natural gas as a heating fuel. Together, the residential and commercial sector accounted for a little less than 50 percent of natural gas consumption in Washington State in 1999. Along with small industrial customers, these are the core market sectors for natural gas distribution utilities.

Industrial natural gas consumption tends to be more volatile and price sensitive than the residential and commercial sectors. During the 1980s natural gas consumption was less than half the amount in 1973 and did not return to the 1973 peak until 1998. Industries use natural gas primarily for process heat and, in some cases, as a direct input to manufacturing of substances such as plastics and fertilizer. When natural gas supplies were unreliable and prices high from the mid 1970s to the early 1980s, industries used other fuels for process heat or they cut back production. During this period there was growth in the consumption of biofuels, but overall energy use in the industrial sector dropped 10 to 15 percent.

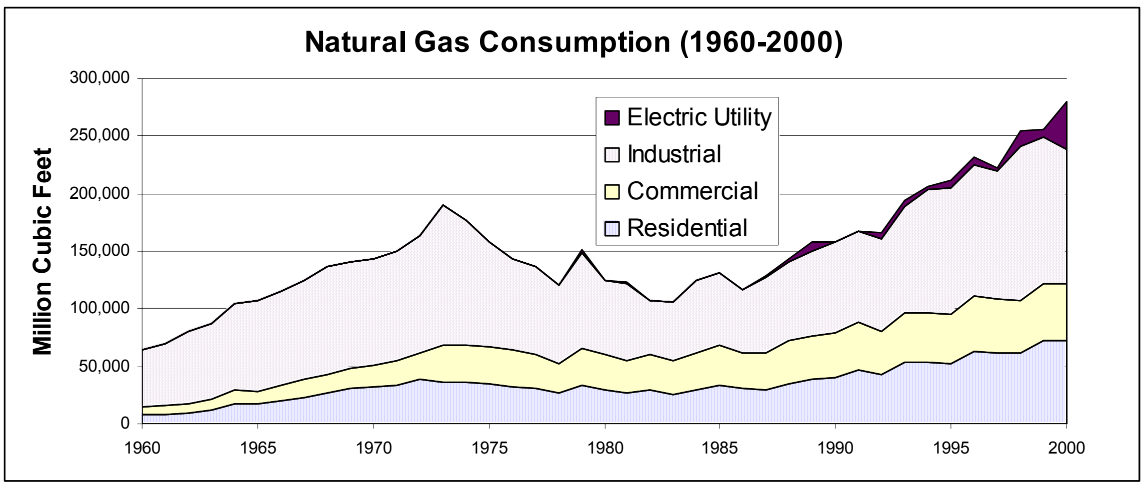

Figure 1.4. Historical Natural Gas Consumption in Washington State Source EIA

In the Pacific Northwest, the consumption of natural gas for electricity generation historically has been for utility-owned natural gas-fired peaking generators. These plants were designed to be used a limited number of days per year to meet peak system demands. Use of these plants was limited during the 1980s and early 1990s and consumption of natural gas in the utility sector was low.

But this situation began to change during the 1990s. New gas-fired cogeneration facilities[3] went on line at a half-dozen industrial sites in Washington State and these were

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[3] These cogeneration plants were installed at oil refineries and wood products facilities. Cogeneration plants generate electricity and the waste heat from electricity generation is used as process heat by the host

followed by a number of gas-fired power plants. New combined cycle combustion turbine technology (CCCT)[4] coupled with extremely low commodity gas prices made natural gas the nearly universal fuel of choice for electricity generation. Gas plants were relatively inexpensive to construct and operate,[5] and environmentally were much preferred to coal or nuclear plants. In contrast to peaking generators, these new plants were intended to run most of the time and they rely on natural gas as their only fuel, although some of the cogeneration plants built in the 1980s and 1990s can also use other fuels such as wood waste, refinery gas, or spent pulping liquors. As these natural gas power plants began to come on line, new demands were placed on the natural gas system.

It is important to note that natural gas consumption for power plants owned by industries or independent power producers is included as part of industrial sector energy consumption in the historical data shown in Figure 1.4.[6] From 1991 to 1995, six new cogeneration plants went into operation at industrial sites in Washington State. The Energy Information Administration (EIA) recently estimated that about 25 to 30 billion cubic feet (Bcf)/year of industrial natural gas use during the 1997 to 2000 period was for electricity generation. Thus the consumption of natural gas for electricity generation grew from minimal amounts in 1990 to over 70 Bcf in 2000, which is about a quarter of total natural gas consumption in Washington State.

2000-2001: The West Coast Energy Crisis

The West Coast energy crisis that began in mid-2000 and ran through most of 2001 caught government, utilities, businesses and consumers by surprise. The events of this period represent a substantial departure from past expectations of natural gas and electricity markets. We briefly review the situation here. For a more complete discussion see Karier 2001 and CEC 2001.

Adequate energy supplies and relatively low energy prices in the 1990s set the stage for the energy crisis. Wholesale gas prices dropped as low as \$1/MMBtu, and wholesale electricity prices ranged between \$10 and \$20/Megawatt-hour (MWh)[7] through 1997. Depressed gas prices led to limited gas exploration in the U.S. Rocky Mountain areas,

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industry. This can increase the overall plant efficiency because a larger portion of the energy input is used.

4 Combined cycle combustion turbines utilize the waste heat from the first stage of electricity generation in a second stage, thus boosting power plant efficiency.

5 The Fourth Northwest Conservation and Power Plan (Northwest Power Planning Council 1998) estimated levelized electricity costs (includes amortized capital costs and fuel and operating costs) for a new combined cycle natural gas generating plant to range from 2.7 to 3.2 cents per kilowatt-hour (kWh). This was the least expensive generating resource with the exception of low-cost hydro. For comparison, coal plants had a levelized cost of 3.7 to 4.2 cents/kWh, wind was 3.6 to 7.5 cents/kWh, and nuclear was 4.3 cents/kWh.

6 Recently, the Energy Information Administration has updated the accounting methodology for the electric power sector, such that it includes utilities, independent power producers, and others whose primary business is to generate electricity.

7 A Mega-watt hour (MWh) is equal to 1000 kWh or 10^6 watt-hours.

and slower growth in gas drilling in Canada. Low electricity prices and uncertainty in electricity markets resulted in little new power plant construction in the Northwest.

Yet demand for electricity and natural gas continued to grow throughout the 1990s as a result of population growth in the region and a strong economy. But the impact of this growth on energy supply was masked by mild weather and favorable hydroelectric conditions. Cool summers and warm winters moderated the demand for electricity (and natural gas-fired generation) in the summer and natural gas space heating in the winter. A surplus of low-cost hydroelectricity reduced the natural gas demand from natural gas power plants, particularly in California.[8]

This all changed in 2000 and 2001 when a confluence of events increased energy demand, constrained supply, and contributed to extreme market volatility.

- Colder than normal winter temperatures across the country in the winter of 2000-01 put additional demands on an already strained natural gas system. Natural gas prices increased sharply nationwide to $8-10/MMBtu.

- Drier conditions in the Pacific Northwest and the West Coast in 2000 and a drought in 2001 resulted in substantial reductions in hydroelectricity capacity. Annual hydroelectric production on the Federal Power System in 2001 was 45 percent less than production in 1997 and 40 percent less than 1999: a 4,000-5,000 average Megawatt (aMW) deficit.[9] This mirrored the situation in the Western Electricity Coordinating Council (WECC), where hydroelectric generation was also 40 percent less: a 10,400 aMW deficit in 2001 relative to 1999. Natural gas-fired generation picked up the largest share of this decline in the Western States region (Table 1.1). This was a primary contributor to the energy crisis.

Table 1.1. Electricity Generation by Major Fuel Type, WECC

	Generation by Fuel Type, January to December (GWh)[10]			
	2001	2000	1999	Difference 1999 to 2001
Coal	231,621	234,501	226,987	2%
Nuclear	70,194	74,162	69,874	.5%
Hydroelectric	135,987	193,561	227,419	**-40.2%**
Natural Gas	174,361	158,193	126,457	**37.9%**
Other	30,179	26,909	29,063	3.8%
Total Generation	*642,342*	*687,326*	*679,800*	*-5.5%*

[8] Hydropower production on the Federal Power System was generally about 10 percent above normal from 1996 through 1999.

[9] An average megawatt (aMW) is equal to one megawatt of production/consumption over a one year time period, or 8,760 Megawatt-hours.

[10] A Giga-watt hour (GWH) is equal to 10^9 watt-hours.

- North American natural gas production capacity continued to fall thru the 1990s[11] and natural gas put into storage during the April to October storage period was about 10 percent below normal, reducing available supply for the following winter. This made for a very tight balance between supply and demand.

- The structure of California's deregulated electricity market contributed to price volatility in electricity and natural gas markets. Electric utilities in California had to divest their generation resources and purchase the vast majority of their power on hourly markets, thus limiting their ability to control market risk. Some companies engaged in questionable trading practices and withheld supplies in an attempt to raise market prices. Extremely high margins in electricity markets created upward pressure on natural gas prices.

- There is also evidence that some companies reported false information to publishers of natural gas price indices in order to affect favorable movements of published prices. FERC is currently investigating these concerns to ensure that prices are transparent and the market functions properly, and a number of federal criminal probes are under way.

- An explosion on the El Paso natural gas pipeline in New Mexico took a significant amount of transmission capacity to California out of service. El Paso was also alleged to have intentionally withheld pipeline capacity during 2000 and 2001, and recently agreed to pay parties in California billions of dollars to settle claims against the company: Washington and Oregon also received settlement money. Pipeline capacity constraints during the winter of 2000-2001 pushed up prices for delivery points on the West Coast. For example, during December 2000 price differentials between producing areas in the Rocky Mountains and Alberta, Canada, and delivery points in California and the Northwest grew to $10-20/MMBtu. These price differentials tended to be more pronounced and longer lasting for delivery points in California.

The energy crisis produced a dramatic increase in wholesale prices for natural gas. Figure 1.5 shows average monthly wholesale natural gas prices at the Sumas trading hub. Prices peaked at $17/MMBtu relative to historical values around $2/MMBtu. Prices in Southern California spiked as high as $50/MMBtu during this period. It is interesting to note that wholesale natural gas prices on the West Coast did not rise dramatically until the peak heating season, when demand for heating combined with demand for natural gas generation pushed the natural gas supply and delivery system to the limit. By fall 2001 prices had returned to historical levels.

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[11] The gas industry was producing at over 95 percent of capacity by 2000 versus about 85 percent of capacity in 1990.

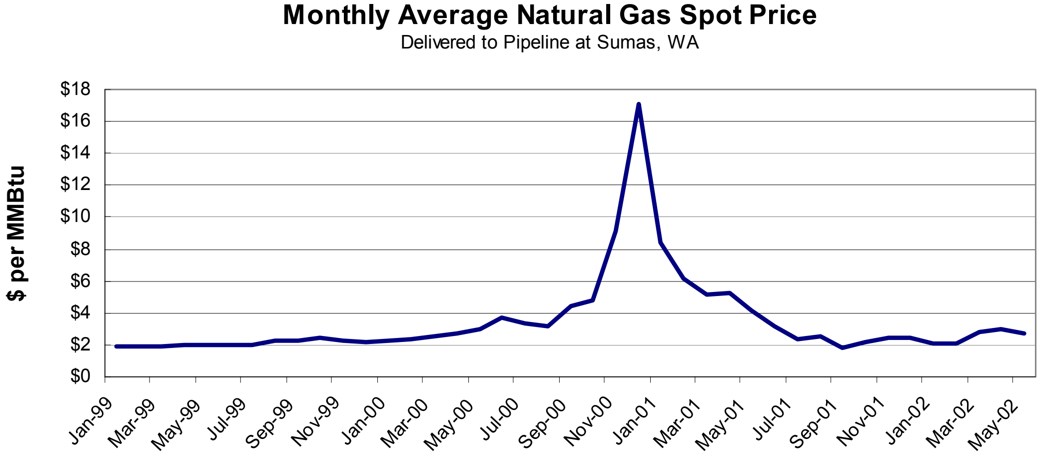

Figure 1.5. Wholesale Natural Gas Prices Source Nat. Gas Weekly

Higher wholesale natural gas prices translated into higher natural gas prices for consumers. In Washington State, gas utilities use Purchased Gas Adjustments (PGA) to pass through actual gas acquisition costs to retail customers with periodic rate adjustments, subject to Washington Utilities and Transportation Commission audit and review.[12] As a result, consumers saw the price they paid for natural gas increase relatively quickly (Figure 1.6). In 1998, the average residential price for natural gas was $5.84/Thousand cubic feet (Mcf),[13] but by Summer 2001 the price peaked above $11/Mcf before dropping a little below $10/Mcf. Similarly in the commercial sector, the price went from an average of $4.75/Mcf in 1998 to a little more than $9/Mcf by mid-2001. In 2001, the average residential consumer paid $360 more than in 1999 for natural gas and the average commercial consumer paid $2,330 more. Note that many industrial consumers do not purchase their natural gas from retail utilities, thus this information is not publicly available. The impact of higher wholesale natural gas prices on industrial customers largely depended on the nature of their contracts with natural gas suppliers.

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[12] Each natural gas local distribution company makes a PGA filing each year, which establishes natural gas costs for the coming year. This process looks at past costs as well as future projections and makes adjustments as needed (Washington Administrative Code (WAC) 480-90-233). The PGA is intended to pass actual utility costs for acquiring natural gas to customers. Avista has a price benchmark mechanism in their natural gas tariff that provides an incentive to them if they beat the benchmark in their purchases of natural gas. Puget Sound Energy used a similar incentive mechanism that gave them the opportunity to earn a profit on the commodity portion of gas sales if they beat a price index, but use of this incentive has ended. Cascade Natural Gas and Northwest Natural Gas have never used an incentive mechanism.

[13] One thousand cubic feet (Mcf). One thousand and thirty cubic feet is equivalent to one million Btu, depending on the exact energy content of the natural gas. For practical purposes 1 Mcf = 1 MMBtu.

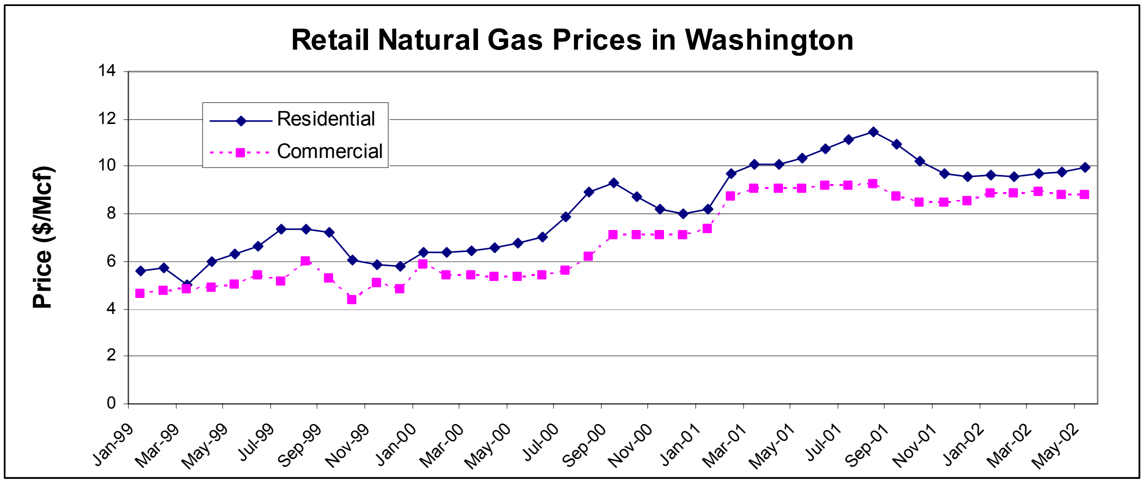

Figure 1.6. Natural Gas Prices during the Energy Crisis for Residential and Commercial Consumers Source EIA, BEA

In California, there were a small number of rolling blackouts in the winter and spring of 2001 due to insufficient electricity supplies. A significant number of blackouts were expected in summer 2001, but these were avoided largely due to an unprecedented degree of conservation and demand reductions from consumers in both California and the Pacific Northwest and the addition of temporary and permanent generating capacity. This included the shutdown of aluminum smelters in the Pacific Northwest, which accounted for a sizable portion of the load reduction in the region. Even though supplies were tight, there were no reliability problems. A small number of customers paying market based rates for energy chose to discontinue service during this period due to high energy costs. There are a small number of utility customers with interruptible natural gas or electricity service. At times these customers can have their service shut down during peak periods under the terms of their interruptible contracts. This rarely occurs and if it does it is usually a result of constraints on a local utility system. Although there are no specific data available, we are not aware of any interruptions of service to these customers in Washington State due to the West Coast energy crisis.

Was the energy crisis of 2000 and 2001 an isolated event? Will the pre-crisis situation of adequate energy supplies and stable prices return? The events of 2000 and 2001 clearly illustrated:

- The convergence of natural gas and electricity energy markets. The growing demand for natural gas for electricity generation ensures that this will continue.
- Pacific Northwest natural gas markets are not isolated, but are influenced by events on the West Coast and throughout the rest of the country.
- In 2001, the Pacific Northwest natural gas supply and delivery system was nearing its capacity and had limited ability to meet additional demand without expansion.

These lessons from 2000/2001 suggest that there is potential for continued volatility in natural gas markets in the Pacific Northwest.

Post Crisis Period

By late 2001, both wholesale electricity and natural gas prices had returned to historic levels. It appeared the crisis was over. More favorable weather, the effects of the recession, the aluminum smelters going off line in the Northwest, and better hydro conditions all reduced demand for natural gas. But this situation began to change towards the end of 2002 as the result of colder weather and low natural gas storage levels in the eastern United States. Spot market prices in the Pacific Northwest rose to \$5/MMBtu by February 2003, spiked to \$8/MMBtu in early March, and are remaining near the \$5 level (Figure 1.7). Prices spiked even higher in other parts of the country, reflecting national market conditions.

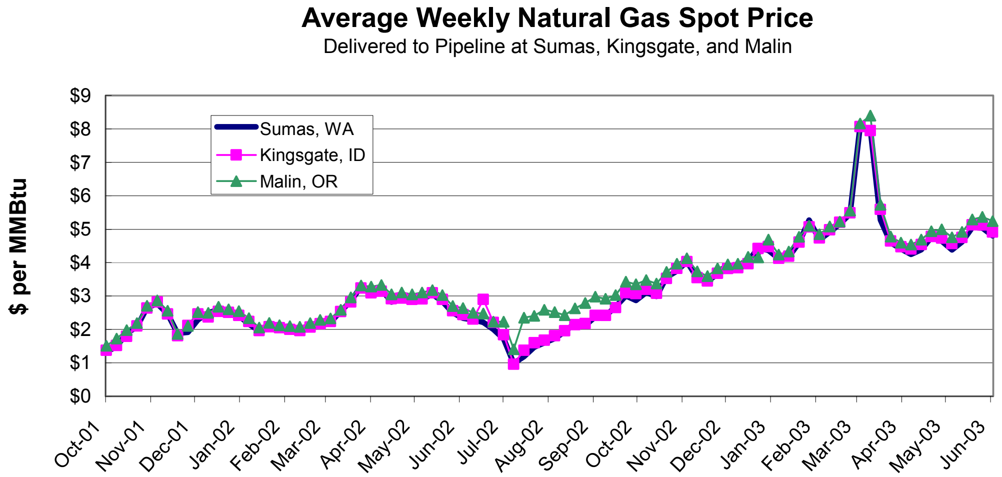

Figure 1.7. Recent Wholesale Natural Gas Prices in the Northwest
Source Nat. Gas Weekly

The near-term outlook for U.S. natural gas markets suggests there will be upward pressure on prices and there is potential for continued market volatility. Limited growth in natural gas supply combined with increased demand has resulted in a tight balance between supply and demand. Output from conventional sources for natural gas may not be able to meet growing demand, suggesting the need to develop more expensive non-conventional sources, such as coal-bed methane. Natural gas future prices were around \$6/MMBtu through 2004, suggesting future prices might continue to be higher than historical values.

The use of natural gas for electricity generation has been driving the growth in demand for natural gas nationally. In 2000, plans called for the bulk of the Pacific Northwest region's growth in electricity demand to be met with natural gas-fired generating capacity; and at the time over 12,000 MW of natural gas-fired generation was in various stages of construction, permitting or planning in the region. Market conditions have changed and electricity demand and prices are down, making the situation less favorable for construction of some of these plants. But a significant amount of natural gas-fired generation capacity has recently come on line or is under construction.

Table 1.2 identifies the capacity of plants that have been recently constructed in the Pacific Northwest as well as those under construction and in different stages of planning. The capacity of plants that have come into service (on line in 2000 or later) plus those under construction is greater than the total existing capacity. But over 7,000 MW of new capacity, some of it under construction, has been deferred, suspended or terminated. And few of the plants that are permitted or planned are likely to be constructed given recent declines in electricity demand and little likelihood of returning to current levels of demand in the near term.

Table 1.2. New Natural Gas Power Plants in the Pacific Northwest Region

Status	Number	Capacity (MW)
Existing (pre-2000)	28	3180
Recently In-Service	27	2867
Under Construction	4	867
Permitted	11	5551
Permitting/Planned	13	6290
Potential	8	2633
Retired	5	282
Deferred	5	3001
Suspended	3	1176
Terminated	21	3047

Source: Northwest Power Planning Council, October 2003

In the remainder of the report, we examine key issues about uncertainty and price volatility in natural gas markets including growing demand, reduced demand responsiveness, supply uncertainty, and constrained infrastructure. In Section 2 we review natural gas reserves and resources. Section 3 examines natural gas production by region; Section 4 focuses on recent long-term natural gas supply, while Section 5 delves into recent demand forecasts. Section 6 gives a review of recent natural gas price trends and market forecasts, while Section 7 provides an overview of gas pipeline and storage capacity and the ability of this infrastructure to meet needs in the region. The report concludes with a summary of key findings (Section 8) and a presentation of policy issues (Section 9) at the national and regional level. Five appendices are included covering: a.) The possibility of peak natural gas production in North America, b.) Proposed LNG facilities in North America, c.) Price-demand dynamics in the natural gas market, d.) Utility energy efficiency programs, and e.) Financial tools for natural gas portfolio management

Section 2: North American Natural Gas Resources

Introduction

The ability of natural gas resources to meet future demand is a critical question for the nation and the Pacific Northwest. Natural gas resources are estimated by several federal agencies, primarily the Minerals Management Service (MMS), the U.S. Geological Survey (USGS), and the Energy Information Administration (EIA). In addition a business, government and academic group, the Gas Potential Commission (GPC), produces an estimate of U.S. natural gas resources every two years. The National Petroleum Council (NPC) also periodically assesses U.S. natural gas resources. In Canada, a counterpart to the GPC, the Canadian Gas Potential Committee (CGPC) estimates the size of the gas resource base. Two government organizations the National Energy Board (NEB) and the Alberta Utility and Energy Board (AEUB) also make estimates of Canadian gas resources. Unfortunately, the various resource-forecasting entities use slightly different definitions, terms, and methodologies when making their assessments

Natural gas is typically found concentrated in pockets that have been formed within particular types of geological formations (traps) located at certain depth ranges. Geologists group natural gas resources into two broad classes: conventional and unconventional. Natural gas found in concentrated in pockets is referred to as a *conventional gas resource*, and is relatively easy to extract. Conventional resources can be located onshore or offshore and currently account for about 75 percent of U.S. production, a percentage that is projected to steadily decline over the next several decades (EIA 2004). A major subcategory of the conventional gas resource is *associated natural gas*, which is dissolved gas associated with oil production. In the past, much of the extracted gas was associated natural gas, and was often flared or re-injected to maintain oil reservoir pressure. Today, only about 15 percent of natural gas produced in the United States is associated with oil deposits (EIA, 2001). Some of the natural gas produced today is not concentrated in pockets, but is of a more dispersed nature. This dispersed type of gas is referred to as an *unconventional gas resource*, and has subcategories of tight sand gas, coal-bed methane gas, and gas shales resources. Unconventional gas requires special extraction techniques and is more challenging and expensive to extract. In 2002, unconventional natural gas production was just over 25 percent of total U.S. gas production. Over the last 15 years, production from tight sands and coal-bed gas resources has grown steadily and in 2002 accounted for 19 percent and 8 percent, respectively, of U.S. production.

Several key terms are used to describe natural gas resources. Two important terms are *proved reserves* and *potential resources*. The expressions *total resource base* and *technically recoverable resource* are also commonly used terms and refer to the sum of proved reserves and potential resource. A newer and less commonly used term is *commercial* or *economical resource*, which is used to describe the amount of the total or technically recoverable resource that can be brought to market at a specified price using a given set of technological assumptions. Two other related natural gas terms are *annual production* and *cumulative production.* Unlike the other terms above, which are estimates, these last two terms are actually measured quantities. The media often mistakenly interchange these terms. A brief discussion of the terms used to describe gas reserves and resources is given below.

Proved Natural Gas Reserves

Proved natural gas reserves are estimated quantities that at a particular time are demonstrated by geological, engineering and economic assessments to be recoverable. Generally, under given economic and technological conditions, there is at least a 90 percent probability that the recovered volume will exceed the estimated proved reserves volume. Thus proven reserves are a conservative estimate of the resource available. Market price for natural gas and the level of extraction technology available will influence the proved reserve levels even if there is no change in assessment of physical gas supply. Some entities, such as the GPC, use terms like probable reserves, possible reserves and speculative reserves. These last three reserve categories are technically and economically less secure and have lower probabilities of being brought into production than proved reserves. The probable, possible and speculative reserves in combination are roughly equivalent to the potential resource term described later in this section.

Each year gas production reduces the level of proved reserves in a given gas basin. Exploration and development are necessary to move natural gas from the potential (undiscovered) resource category to the proved reserve (discovered) category. Each year as reserves are consumed, exploration and development replaces some, all, or more than the amount of gas consumed. As a producing gas basin matures reserve additions become more difficult to obtain, and they may begin to fall behind gas production; consequently proved reserve levels begin to fall, and soon after, production will also begin to decrease. The term *reserve to production ratio* (Reserves/production, or R/P) is often used to describe the vitality of a gas basin. Ratios of more than 20 describe a young basin with production expansion potential, 10 to 20 a maturing basin, and less than 10 an older basin that may soon reach a production peak. Technological innovation and higher gas prices can forestall the day when reserve additions begin to fall behind gas production. Less mature gas basins are likely to see increases in both reserves and the assessed potential resource categories on a year-to-year basis.

Figure 2.1 below illustrates the decline in R/P and proved reserves for both U.S. oil and natural gas for the period 1949-2001. Following World War II the natural gas market expanded rapidly, and the R/P began to decline reaching a value of 20 in the early 1960s. Much of the initially developed natural gas was associated gas, or was incidentally discovered during oil exploration. Low regulated natural gas wellhead prices resulted in a rapid increase in gas consumption and the R/P continued its decline through the 1960s and early 1970s. Actual proven gas reserves and production began to decline in the early 1970s, which pushed the government to significantly raise the regulated wellhead price for gas, and later initiate the deregulation process for natural gas in 1978 with the passage of the Natural Gas Policy Act. These actions stimulated a sizable amount of gas exploration, which stabilized natural gas reserves and caused the R/P to increase beginning in the mid 1980s. Since deregulation was completed around 1990, energy companies have developed reserves as necessary to meet projected near term production requirements. In the 1990s, U.S. gas reserves declined and the R/P reached a low of 8.6 in 1997. Over the last several years high prices have led to increased exploration activity and the R/P has risen to 9.3.[14] The low R/P for natural gas and the nation's experience with long-term low R/Ps for oil and associated declining oil production has caused concern in some quarters that natural gas production will also begin an inexorable decline. While the low R/P could be a sign of a declining resource base, maintaining only sufficient inventory (reserves) to meet near term production requirements is also a reasonable financial technique for energy companies to reduce capital costs: See Appendix A for more discussion about the future sufficiency of the North American gas resource base.

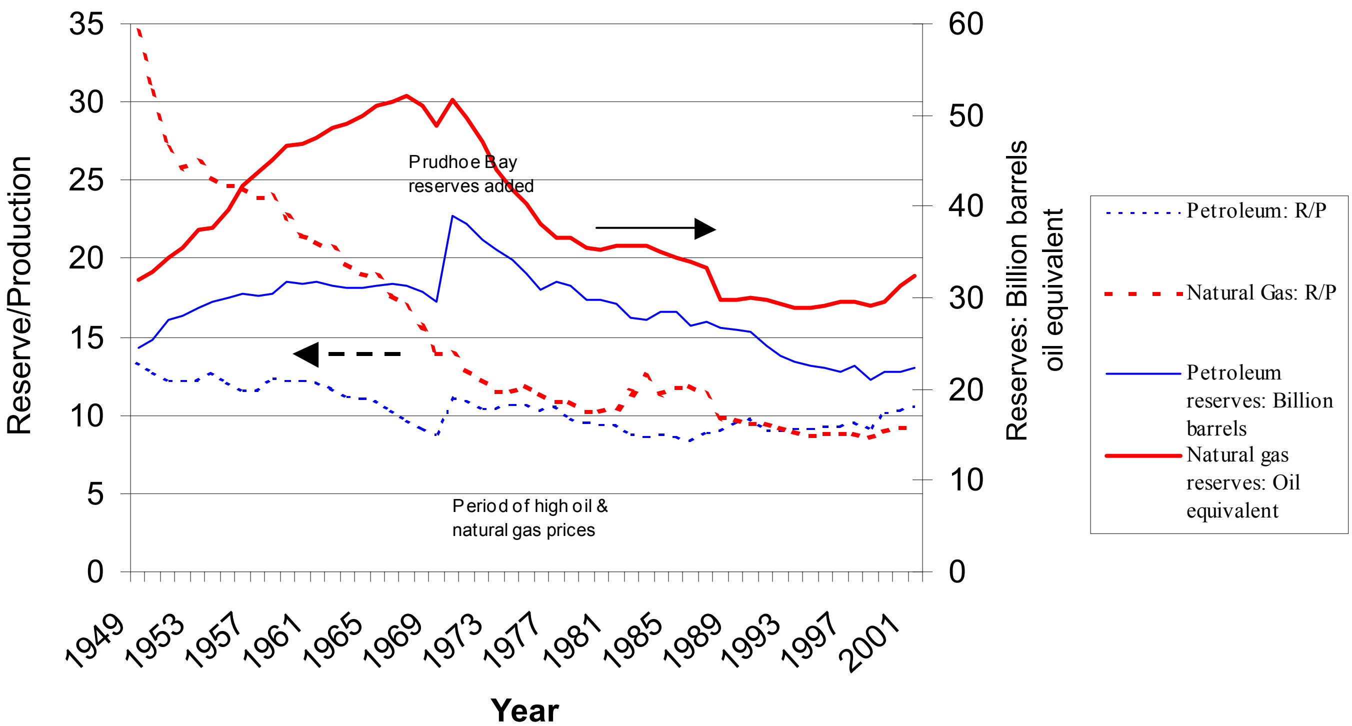

Figure 2.1: Petroleum and Natural Gas Reserve to Production Ratios: 1949-2001

Source EIA

In 2002, additions of 22.8 trillion cubic feet (Tcf), or 118 percent of U.S. gas production (roughly equivalent to 2002 U.S. consumption) were made to proven reserves. During seven of the last 10 years, gas additions to reserves, have exceeded U.S. production: additions exceeded total U.S. consumption for three of the last 10 years (EIA, 2002).

Reserve Additions

As noted above, proven reserves are a conservative assessment of natural gas (or oil) resources. Additions are made to proven reserves by two means: discovery of new fields, and reserve growth. Approximately 20 percent of additions are new fields, and 80 percent

[14] The National Petroleum Council has noted that even though the R/P has risen over the last several years the ratio of actual producing reserves to production has not increased, remaining at around 6.5.

are from reserve growth. Reserve growth is sometimes referred to as reserve appreciation. When estimating total or technical resource base, forecasts are made regarding new field discoveries and reserve growth. Historical geological and production data are used to develop forecasts about the size of the undiscovered fields and the rate and size of reserve growth. Reserve growth is often calculated using a reserve growth or appreciation factor. Recent geological and production data have resulted in downward revisions in forecasted size of new field additions and reserve growth. Figure 2.2 below illustrates the recent downward trend in gas recovery per connection for the U.S. Lower 48 (the 48 state continental portion of the United States) and Canada.

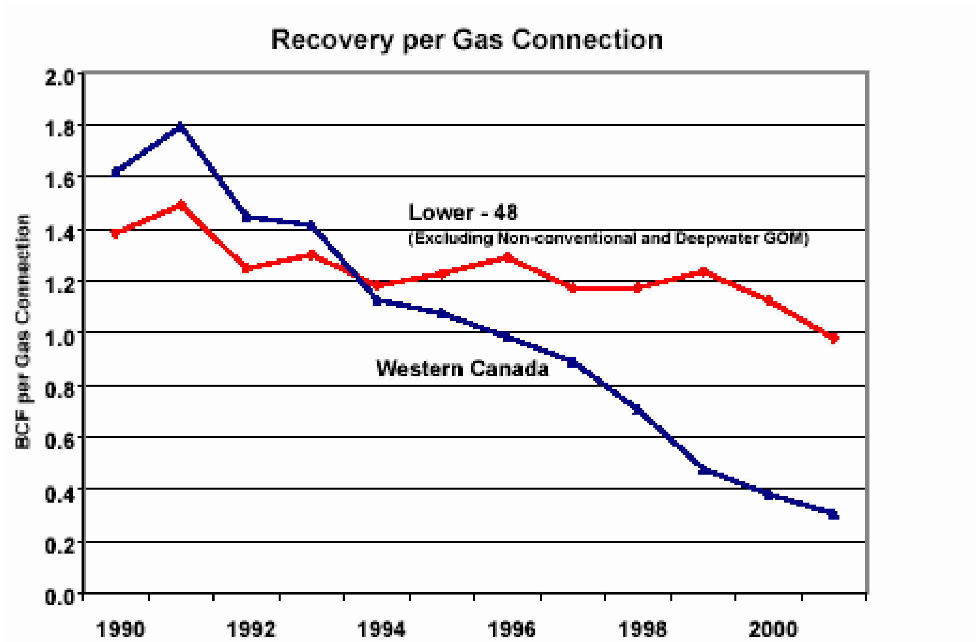

Figure 2.2: Estimated recovery per gas connection.
Source NPC 2003

The progressive decline in gas field size and the application of technology to increase initial production rates of the (smaller) fields has resulted in steeper well decline rates. The overall *annual base decline rate* for the U.S. Lower 48 has increased from 17 percent in 1992 to 27 percent in 2001 (NPC, 2003). The annual base decline rate is the decrease in production over one year that would occur if no new wells were added. The increasing base decline rate necessitates increased exploration and drilling activity every year in order to maintain reserves and production.

Potential Natural Gas Resources

Potential gas natural resources are estimated undiscovered resources, which are thought to exist and be recoverable. The primary organizations involved in providing the basic information used to estimate potential gas resources are the USGS, and the MMS.[15] To estimate the quantity of undiscovered gas resources that can be technically recovered,

[15] In Canada the CGPC and the NEB have the responsibility for estimating gas resources.

geologist combine existing geological information with previous gas extraction experience. Assumptions about future technological developments are also included in the estimation methodology that the USGS and MMS use to calculate undiscovered natural gas resources. The assumptions surrounding projected extraction economics and technological developments range from conservative to very optimistic. Because of variability in the assumptions used by the different resource estimating entities within each step of the resource estimation process, the final resource estimates can vary considerably. The total technical resource base is the sum of proved reserves and potential gas resources.

The Potential Gas Committee (PGC), a volunteer committee comprised of representatives from industry, government and academia, in 2002 produced an updated estimate of the U.S. total resource base. The PGC estimated potential gas resources at 1,311 Tcf, including Alaska and approximately 1,110 Tcf for the Lower 48. This corresponds to 67 times current annual U.S. production and 58 times current annual U.S. consumption. As table 2.1 below shows the largest percentage increase was in the speculative and coal-bed methane categories.

Table 2.1: PGC Potential Gas Resource Estimates for 2000 and 2002.

Resource category	**2002**	**2000**	**Change**
Traditional resources	(Tcf)	(Tcf)	(%)
Probable	210.5	207.0	+1.7
Possible	325.0	332.2	-2.2
Speculative	422.0	397.8	+6.1
Subtotal traditional	958.3	935.8	+2.4
Coal-bed methane			
Probable	17.1	16.3	+4.9
Possible	56.7	54.3	+4.4
Speculative	95.0	84.6	+12.3
Subtotal coal-bed	168.9	155.2	+8.8
Total Potential Resources	***1,127***	***1,091***	***+3.3***
Proved gas reserves	***186***	***177***	***+5.4***

The PGC has estimated the potential natural gas resource since the late 1980s. The PGC's 1988-2002 estimates of potential gas resource, as well as proved reserves and cumulative U.S. production are shown in Figure 2.3 below.

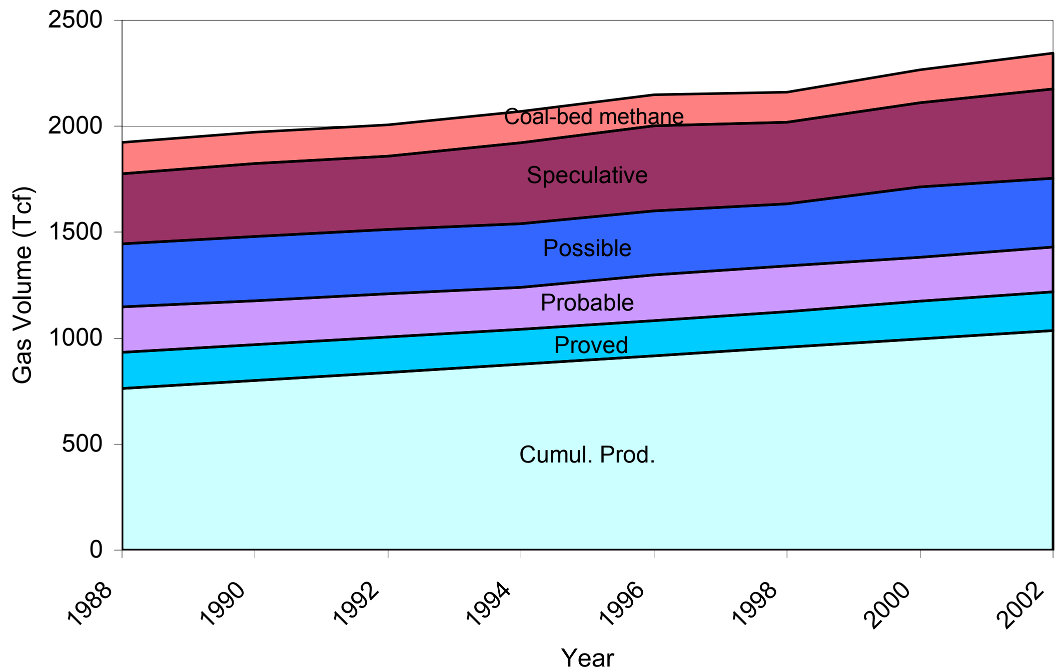

Figure 2.3: PGC estimates of U.S. total potential gas resource and cumulative gas production.

Figure 2.3 illustrates several interesting phenomena. First, the estimated total resource base (potential resource + proved reserves) has increased steadily over the observation time period from 1,160 Tcf in 1988 to 1,311 Tcf in 2002, despite continuing gas production of 17 to 20 Tcf per year. Second, the largest increase has been in the speculative and coal-bed methane categories. Finally, cumulative production is rising slightly faster than the remaining total resource base, and may equal the remaining U.S. Lower 48 total resource base by 2010.

The National Petroleum Council (NPC) has estimated the total U.S. resource base in each of its last three natural gas reports (1992, 1999 and 2003). The 1999 report estimated a total resource base of 1,465 Tcf for the Lower 48, a 171 Tcf increase over the 1992 estimate. However, after a detailed review and a methodology update, the 2003 NPC report showed a reduction to 1,252 Tcf for the U.S. Lower 48 technical gas resource base.[16] This sizable reduction of 211 Tcf was due primarily to lowered expectations for proved reserve appreciation (extensions, infilling wells, etc), and a reduction in the field size (ultimate recovery volume) used for undiscovered fields. The reductions to the

[16] All volumes adjusted to 1999 consumption numbers.

estimated total resource base are based on recent data and reflect an improving understanding of the natural gas resource base at the NPC and the USGS and MMS.

The NPC estimated the total gas resource base for Alaska at 331 Tcf, of which only 9 Tcf was proven reserves, and another 36 Tcf listed as probable reserves. Combining the total resource bases for the Lower 48 and Alaska results in a U.S. total resource base of approximately 1,585 Tcf. While the potential gas resource in Alaska is large, it is not well explored and is essentially a stranded resource.

In its 2001 *Annual Energy Review,* the EIA estimated the total resource base at 1,350 Tcf for the Lower 48. Unlike the 2003 NPC analysis, the 2001 EIA report did not include the recent USGS and MMS adjustments for lowered proved reserve appreciation, a reduction in the ultimate recovery volume for undiscovered fields, or the slight reduction in assessment of the unconventional gas resource. Figure 2.4 below summarizes the recent resource assessments by the NPC, EIA, and the USGS/MMS. All volumes are adjusted to 1999 cumulative production and use the NPC's prediction for advanced exploration and extraction technology.[17] As Figure 2.4 shows the recent assessments have produced significantly lower estimates of the Lower 48 total gas resource base.

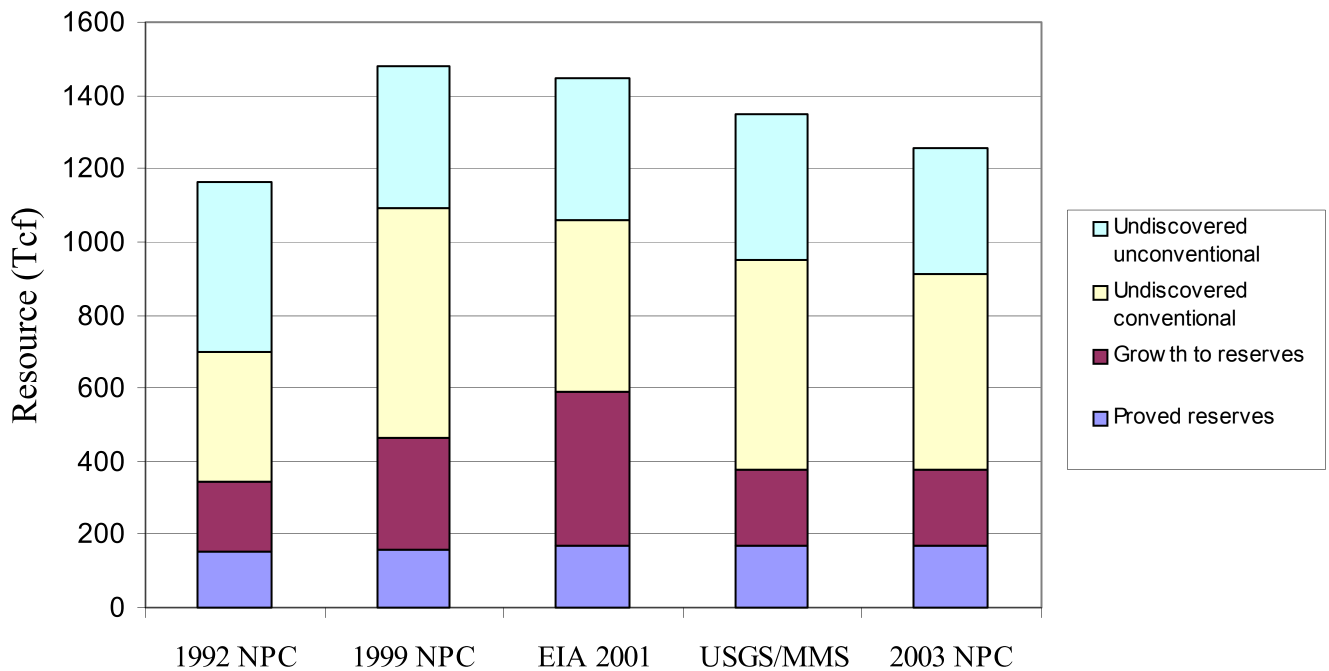

Figure 2.4: Comparison of Natural Gas Resource Assessments-Lower 48

Source NPC 2003

[17] Defined by the NPC as the (projected) exploration and extraction technology for year 2015.

Economic or Commercial Gas Resource Base

As defined above, the technically recoverable or total resource base is the sum of the estimated potential resource and proven natural gas reserves. Some of the potential resource will be located in remote or restricted access areas, or in small pools, which effectively removes it from commercial availability. Over the last few years several organizations that evaluate North American natural gas resources have attempted to estimate the economic or commercial gas resource. The NPC in its 2003 report estimated that 60 percent (760 Tcf) of the U.S. Lower 48 total resource base would be available at a long-term Henry Hub price of $4/MMBtu.[18] At higher prices of $6 and $8/MMBtu, the economic resource base was estimated at 74 percent (940 Tcf) and 83 percent (1,050 Tcf) respectively.

The California Energy Commission (CEC), in preparation for its Natural Gas Market Assessment, estimated the Lower 48 state total gas resource at 975 Tcf and the Canadian resource at 417 Tcf. The CEC further estimated that there was 640 Tcf of commercially available natural gas resources in the U.S. Lower 48 and 332 Tcf in Canada (CEC, 2003) at prices projected over the next decade (2004-2013).

Canadian and Mexican Natural Gas Resources

Canada has significant natural gas resources, 71 percent of which occur in the Western Canadian Sedimentary Basin (WCSB). In 1999, the NPC estimated the total Canadian technically recoverable gas resource base at 667 Tcf, which was a downward revision of 10 percent from its 1992 natural gas report. The 2003 NPC gas report further reduced the estimated Canadian technical resource to 397 Tcf, with current technology, and 475 Tcf with advanced technology. The Canadian Gas Potential Committee (CGPC) in its 2001 (CGPC, 2001) study listed the Canadian natural gas resource (discovered and undiscovered reserves) at 592 Tcf. In contrast to previous studies the CGPC further refined its resource estimate by differentiating between total resource and the nominally marketable resources. Nominally marketable reserves were estimated at only 233 Tcf, and excluded coal-bed methane and some resources located in the Arctic, which have not been demonstrated as economically marketable. Coal-bed methane pilot projects have been initiated, but seem to be hampered by low production rates at the wellhead (Meneley, 2002). A more recent study, which appears to be a counterpoint to the CGPC study, produced by the Canadian Energy Research Institute (CERI), estimated total undiscovered conventional resources at 527 Tcf (Oil & Gas Jouranl, 2003).

Mexico has revised both its gas and oil resource estimates downward over the last several years in order to follow international resource estimation methodologies. In its 2003 natural gas report, the NPC estimated the total Mexican gas resource base at 121 to 147 Tcf depending on assumptions of extraction technology. This was a reduction of more than 50 percent from the NPC's 1992 estimate of the Mexican resource. An even lower resource estimate was presented by the PGC in 2003: Mexican proven natural gas reserves of 28.2 Tcf, and a total gas resource base of only 50.6 Tcf. Mexico has not been

[18] Henry Hub is the largest natural gas hub in the nation and is located on the Gulf Coast.

as heavily explored as the United States or Canada, so the future resource numbers may be significantly greater.

Figure 2.5 below illustrates the three NPC estimates of the North American total resource base. Note that the NPC did not attempt to estimate the total gas resource for Mexico in the 1999 report: For comparative purposes the NPC's 2003 estimate for Mexico was added to the 1999 total.

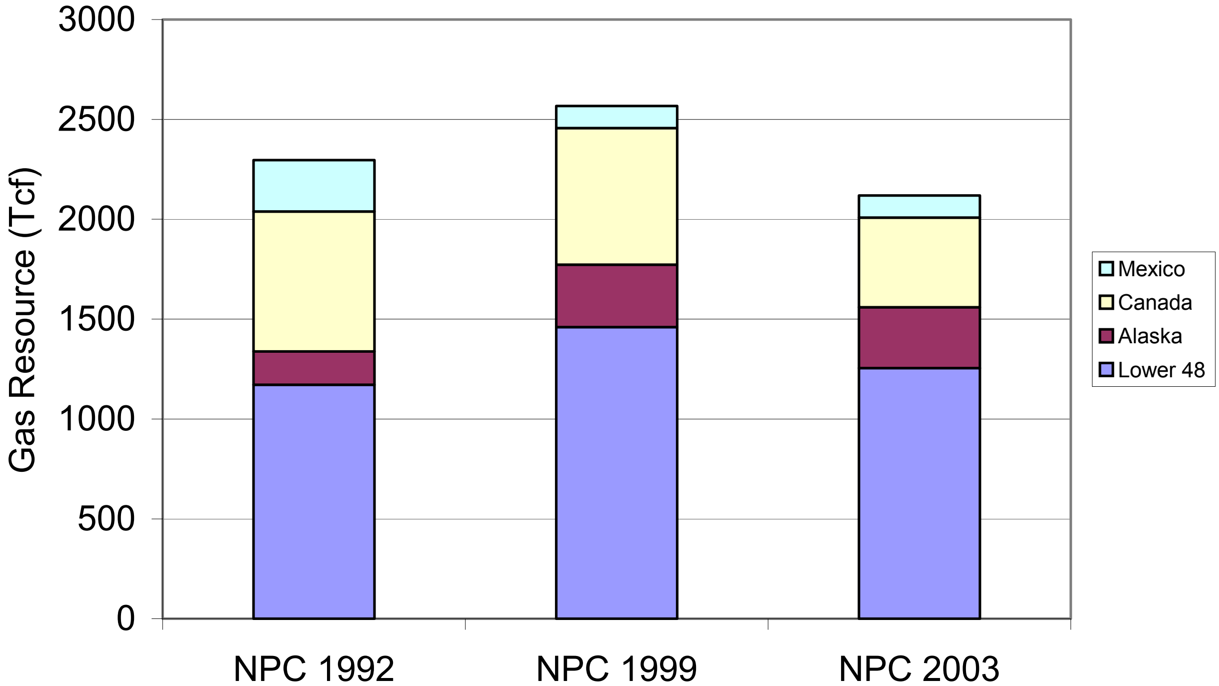

Figure 2.5: National Petroleum Council estimates of total natural gas resource base.

The 2003 NPC estimate for the North American total gas resource is significantly lower than the estimate made in 1999; roughly 20 percent lower. Estimates for both the United States and Canada were significantly reduced in the 2003 report. In addition the estimated total resource base for Mexico was significantly reduced between the 1992 and 2003 NPC reports. The total resource base for Alaska increased between the 1992 and 1999 reports, but at this time must be considered a stranded resource.

Federal Access Restrictions

Substantial amounts of U.S. natural gas resources lie beneath federal lands, or areas designated as wilderness, where access is limited by federal regulations. Most of the restricted access resource areas are located in the Rocky Mountain region. Offshore natural gas resources located in the coastal regions on the Pacific, Atlantic and Eastern Gulf of Mexico area are under a federal development moratorium, and are completely unavailable for gas or oil resource development.

In its report on U.S. Natural Gas Markets, the EIA evaluated the impact of reducing, but not eliminating, federal access restrictions in the Rocky Mountain basin and in the three outer continental shelf moratorium zones (EIA, 2001b). The Rocky Mountain region contains 37 percent of the remaining unproved technically recoverable natural gas resources in the Lower 48. A moderate reduction in access restrictions in the Rocky Mountain basins would free up approximately 29 Tcf of natural gas resource, increasing the region's gas resource by about 10 percent. The outer continental shelf moratorium zones are estimated to have unproved technically recoverable natural gas resources of 68 Tcf. In their analysis, EIA assumed that the phased lifting of the continental shelf drilling moratorium would free up the entire undiscovered natural gas resource in the OCS.

A reduction in federal access restrictions in the Rocky Mountain basin, and in the three OCS moratorium zones, would increase the Lower 48 natural gas resource base by 87 Tcf. This represents a 7 percent increase in the potential natural gas resource base. An estimated 62.5 Tcf of gas, located in national parks, wildlife refuges and wilderness areas in the Rocky Mountain region would remain unavailable for development. In addition, approximately 30 Tcf in other parts of the Lower 48 would remain inaccessible. Note that the quantities of natural gas made potentially available due to reducing access restrictions represent a resource that is technically available, but may not be commercially available, though most analysts believe that the exploration and production (E&P) costs are lower for access restricted resources relative to new unrestricted gas resources.[19]

Assessing the NPC Natural Gas Resource Estimate

The 2003 NPC report contains the most up to date information on the United States and Canadian natural gas resource bases. In the 2003 NPC report, the estimated U.S. resource base was about 14 percent smaller than the estimate in the NPC's 1999 natural gas report. There are several reasons why the actual natural gas resource base available to the nation is less than the 1,585 Tcf cited in the 2003 NPC report.[20]

1. Land use restrictions that severely limit or prohibit access, apply to roughly 205 Tcf of the natural gas resource in the Lower 48 (EIA, 2000). A good portion of this restricted resource base will probably never be developed. For more details see the section on federal access restrictions.
2. The Alaska natural gas resource is currently a stranded resource, and will not be available to the market for at least 10 years. In addition, large portions of this resource, while technically recoverable, are very remote and are not likely to be economically recoverable in the foreseeable future. See the section on Arctic natural gas resource for more details.

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[19] The lower exploration and production costs for access restricted resources are thought to hinder current gas resource development, since a policy change that allowed access to cheaper resources might strand more expensive unrestricted resources that could be developed. North American Natural Gas, American Energy Solutions & Foster Bryan Ltd. 2003.

[20] The sum of the lower 48 state resource estimate of 1,252 Tcf and the Alaska resource estimate of 331 Tcf. Both estimates made assuming NPC advanced (2015) technology.

3. In 2003, the NPC developed estimates of the commercial or economic gas resource base. At a long-term Henry Hub price of $4/MMBtu the NPC estimated that only 60 percent, or 760 Tcf of the total Lower 48 resource base could be economically recovered using advanced technology assumptions.

Summary

A review of the recent natural gas resource assessments by the NPC, EIA and others revealed the following information.

1. Significant quantities of undiscovered natural gas remain in North America.
2. Recent assessments of total gas resource in the U.S. Lower 48 by the NPC, EIA, GPC and USGS/MMS are roughly equivalent, ranging from approximately 1,250 to 1,450 Tcf. Estimates of the Alaska resource range from 220 to 331 Tcf.
3. The 2003 NPC assessment of the Lower 48 gas resource was 1,250 Tcf, a 14 percent reduction from the 1999 NPC report.
4. The 2003 NPC assessment of Canada's total gas resource fell by nearly 30 percent relative to the 1992 assessment.
5. The 2003 NPC assessment of Mexico's total gas resource fell by more than 50 percent relative to the 1992 assessment.
6. The 2003 NPC assessment of the total gas resource for North America was approximately 2,150 Tcf, nearly a 20 percent reduction from the assessment in the NPC 1992 and 1999 reports.
7. The 2003 NPC resource assessment is based on the most current information, and includes the recent adjustments for lowered proved reserve appreciation, a reduction in the ultimate recovery volume for undiscovered fields, and a slight reduction in the assessment of unconventional gas resources.

The 2003 NPC report, and to a lesser extent the 2004 EIA report, indicate that the natural gas resource base is not as robust as it was thought to be just a few years ago. The takeaway message from the supply section of the NPC report is that supplies from traditional North American gas producing basins will be able to supply only about 75 percent of the forecast long-term U.S. gas demand.[21] Investments and policy decisions will need to be made immediately to insure the nation's gas needs are met in the future.

[21] This despite the sizable reduction in the NPC's forecast for U.S. natural gas demand in 2020.

Section 3: North American Gas Production

Introduction

Natural gas is produced in a number of regions, or basins, within North America. This section of the report provides a brief overview of the gas producing regions within Canada and the western United States, with primary emphasis on the two gas producing regions that currently supply the Northwest: the Western Canadian Sedimentary Basin (WCSB) of Alberta and British Columbia, Canada, and the Rocky Mountain region. Because the natural gas market has moved from numerous regional markets, to a more unified national market, a brief overview of other U.S. gas producing regions is included. A brief overview of the natural gas resources and production within Mexico is also presented. Gas producing regions in western North America are shown in Figure 3.1 on the next page.

Canadian Natural Gas Production

Much of the natural gas used in the Pacific Northwest comes from Canadian sources. Canadian production peaked at just over 17 billion cubic feet (Bcf) /day (6.6 Tcf/year) in 2001 and declined slightly to 16.7 Bcf/day in 2002.[22] Canada consumed nearly 8 Bcf/day in 2002, allowing exports of approximately 9 Bcf/day, or about 3.5 Tcf/year, to the United States. Most Canadian gas production and gas reserves are located in the WCSB, which is located primarily in Alberta, but also extends into eastern British Columbia, southwestern Saskatchewan, and a small portion of the Northwest Territories. Most of the Canadian natural gas that Washington State imports comes from the B.C. portion of the WCSB. The central part of the WCSB, primarily in Alberta, was developed first and should be considered a mature producing region with limited growth potential. The western most portion of the WCSB, located in British Columbia, was developed later, and has a higher reserve to production ratio (R/P) and larger field size, which means production growth potential still exists in this part of the WSCB. The gas resources developed thus far are nearly entirely conventional in nature. A large unconventional gas resource exists in the WSCB and will likely be developed in the near future.

Canadian gas exports to the United States rose steadily during the 1990s, from approximately 1.3 Tcf in 1990 to 3.6 Tcf in 2001, and represented nearly 17 percent of total U.S. gas consumption in 2001. Figure 3.2 below illustrates the steady increase in gas imports from Canada over the last 15 years. Note the recent leveling off of Canadian imports in 2001-02, and the slight decline in 2003. The EIA estimates that gas imports from Canada were down 12 percent in 2003 despite sustained high market prices. A portion of the 2003 decline in exports was probably due to the need for additional gas for storage within Canada following the large storage draw down during the winter of 2002-03.

[22] November 2003 production was estimated at 16.2 Bcf/day. Production estimates from Cambridge Energy Research Associates and Statistics Canada.

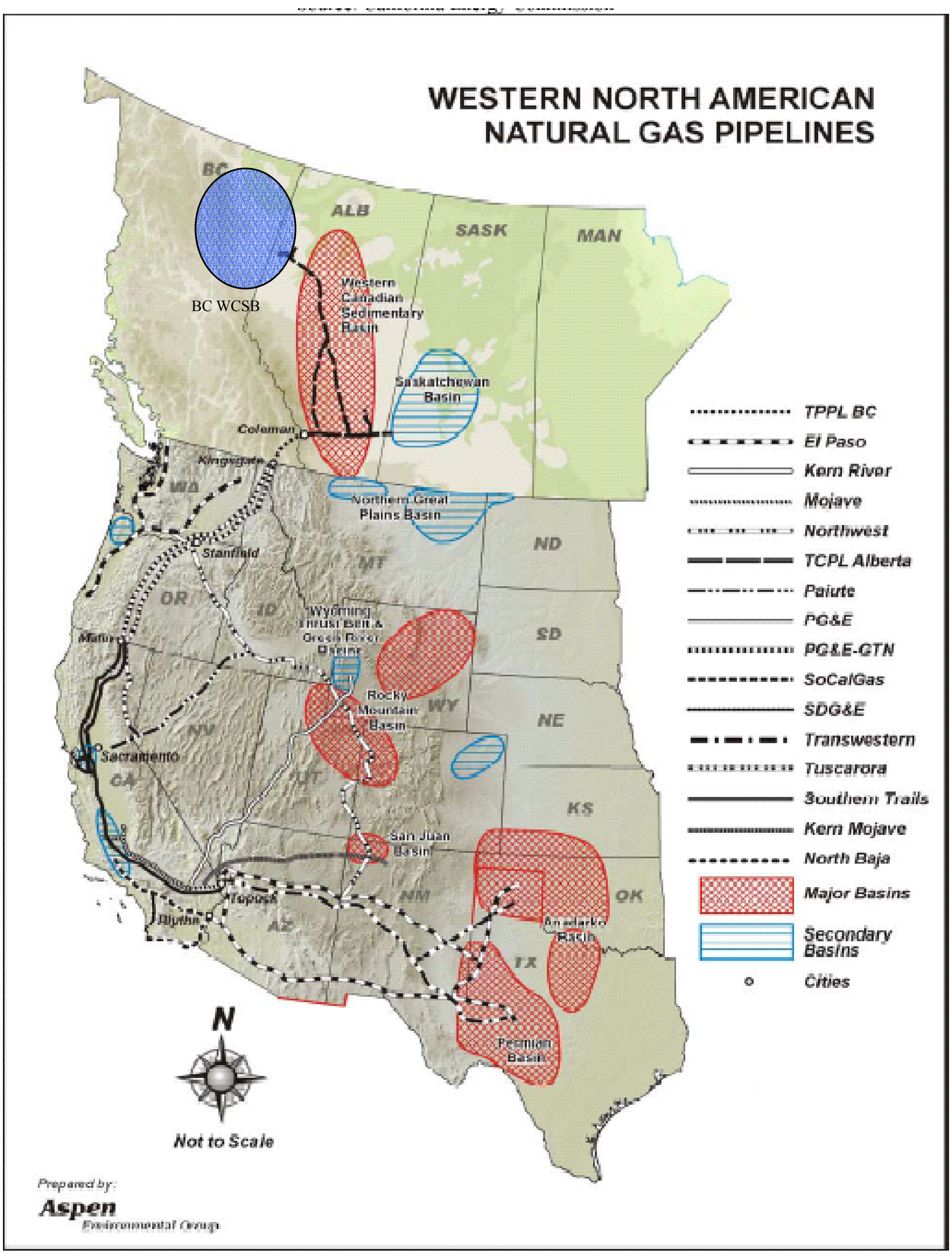

Figure 3.1: Western North American gas producing regions and pipelines.

Source CEC, 2003

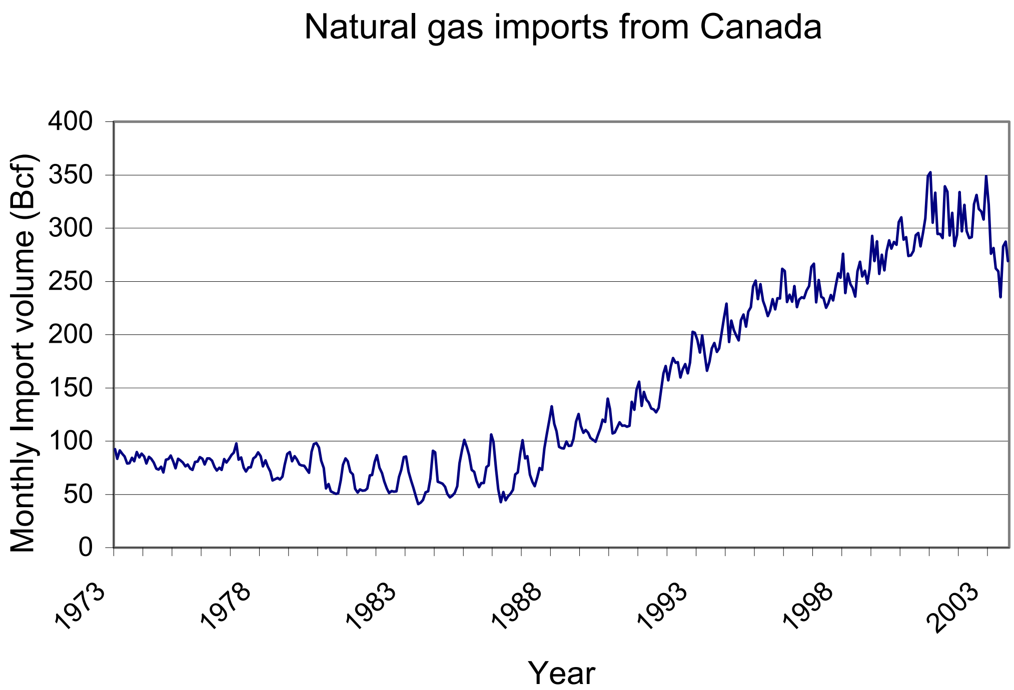

Figure 3.2: U.S. monthly imports of Canadian natural gas 1973-2003,
Source EIA.

The EIA, in its often cited 2001 natural gas report, forecast that over the next 20 years U.S. natural gas consumption would rise to 33.8 Tcf, and that imports from Canada would rise to 5.5 Tcf per year (15.1 Bcf/day). Relative to 2001 consumption, the 2020 forecasts represent a 57 percent increase in overall gas consumption and a 40 percent increase in imports of Canadian natural gas.

Recent assessments suggest that Canadian natural gas exports will not rise to the level cited in the 2001 EIA natural gas report. The Canadian Gas Potential Committee (CPGC) using recent sources of information, stated that conventional gas production from the WCSB will likely be peaking in the around 2005, and that unconventional and Arctic resources will probably only make up for the decline in Canadian conventional gas production (CGPC, 2001). The Alberta Energy and Utility Board reported that Alberta natural gas production (primarily from the WCSB, which represents 75 percent of total Canadian output) fell 3.8 percent in 2002, and predicted production would increase only 1.5 percent in 2003, as a result of the current drilling boom, remain stable in 2004, then fall at 2 percent per year through 2012 (AEUB, 2003). In a similar vein, a report by Thomas Driscoll, energy analyst for Lehman Brothers, states that 2001 may have been the high water mark for Canadian natural gas exports and that they will decline slightly from 9.7 in 2001 to 9.3 Bcf/day by 2005 (Energy Pulse, 2003).

The National Energy Board (NEB) recently forecast that natural gas production from the WCSB would decline slightly from 16.3 Bcf/day at the end of 2002 to 15.8 Bcf/day by the end of 2005 (NEB, 2003). The NEB cited the rapid decline rates and small field size of newer gas wells as the major reasons for the forecast decline in production.[23] The NEB estimated that a record 14,400 gas wells were drilled in Canada during 2003 and that drilling would need to be maintained at 13,400 wells per year to keep production from declining further. The NEB forecast modest increases in Canadian gas production through 2010, to about 18 Bcf/day, followed by a gradual decline in production thereafter (NEB, 2003b).

The Canadian Energy Research Institute study forecast an increase in total Canadian gas production to 19.2 Bcf/day (7 Tcf/year) by 2010, but this was dependent on a near doubling of drilling activity, and a sizable contribution from unconventional gas sources, such as coal-bed methane (CERI, 2003). Cambridge Energy Research Associates (CERA) was also optimistic about Canadian production, forecasting that over the next several years increased drilling and unconventional resources would turn WSCB production around, possibly reaching 18 Bcf/day by 2010.

The Canadian gas industry has had several resource development disappointments over the last two years. Production from Ladyfern, the recent large gas play in northern British Columbia, has fallen by two-thirds from its mid 2002 peak, and will be an insignificant source in a few years. The Deep Panuke project off of Nova Scotia has been delayed because of disappointing exploratory wells. Development of the Mackenzie Delta resource is moving forward, but will take nearly five years to complete, and will only add modestly to Canadian production. Coal-bed methane, tight sands and deep well natural gas hold significant potential. However, to date unconventional resources have seen little development activity in Canada, largely because of high extraction and infrastructure costs. It will be several years before unconventional resources contribute significantly to Canadian gas production.

A number of factors might limit Canadian exports to the United States over the next five to 10 years. Stagnant production, growing demand within Canada for natural gas, and public opposition to gas exports, have the potential to reduce Canada gas exports. Demand for natural gas by the oil sand projects,[24] and the need to replace existing coal power plants to meet Canada's Kyoto protocol requirements are additional factors that could limit natural gas exports from Canada.[25]

Because of the above factors, it is likely that Canadian exports to the United States will be flat or decline incrementally over the next several years and then rebound slightly as natural gas from unconventional resources and Mackenzie Delta begins to enter the market around 2008. Because the short-term decline in Canadian exports is expected to be small, and since Washington State receives most of its gas from British Columbia,

[23] The NEB estimated the overall decline rate for existing wells in the WCSB at 23 percent per year.

[24] Oil sand production currently consumes 300 to 400 MMcf/day and it is estimated that this will increase to at least 500 and possibly to 1,000 MMcf/day by 2010. Source: National Research Council Workshop on Natural Gas Supply and Demand 2003

[25] The Kyoto accord will put pressure on Canada to convert some of its 5,000 MW of coal fired electric capacity to natural gas to lower carbon dioxide emissions.

where production is forecast to grow over the next several years, the near-term impact on the state should be modest. After 2010, declines in Canadian exports are likely to resume as overall gas production plateaus and internal demand continues to grow. This could present a problem for consumers in Washington State if new supply sources are not brought to market in a timely manner: The EIA and the NPC forecast declines of 25-50 percent in Canadian imports by 2025.

Rocky Mountain Natural Gas Production

The Rocky Mountain region is an area of high current and potential natural gas production. Proved reserves are 35 Tcf and 2002 production was 1.9 Tcf. Production has risen steadily in the Rockies region, increasing by approximately 25 percent in the last five years alone. The EIA forecasts that gas production from this region will increase by 2.7 Tcf per year by 2020 (EIA, 2003). This region also contains approximately 35 percent (293 Tcf) of the remaining undiscovered technically recoverable natural gas in the Lower 48 onshore United States. Most of the Rocky Mountain resources are *unconventional*: 65 percent in tight sand formations, and 16 percent classified as coal-bed methane (EIA, 2001b). Environmental and other constraints currently limit access to about 45 percent of the resource.[26] Efficient development of the resource is further restricted by the complex nature of the reservoirs found in the Rocky Mountain basins that require special geological characterization, drilling, and production techniques to become economically feasible to produce. In addition, the U.S Environmental Protection Agency (EPA) and U.S. Bureau of Land Management (BLM) have recently developed stricter requirements for the disposal of process water and land use, which will add to the cost of resource development in the Rocky Mountain basins.

Despite the challenge of extracting the gas resource it is anticipated that production will continue to increase in the Rocky Mountain region. However, due to resource access restrictions and environmental concerns, the increase in production forecast by the EIA (production of 4.5 Tcf per year in 2020) may be optimistic.

Gas Production In Other Basins

Although Washington State receives the bulk of its natural gas from Canada and the Rocky Mountain basins, production from other regions is also of interest due to the increasingly integrated nature of the North American natural gas market. Most of the gas producing regions are located in the south central part of the nation and are in general mature highly developed resources. Figure 3.3 below illustrates the gas production in a number of regions within the United States.

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[26] The Rocky Mountain resource volumes under access restrictions are consistent with the findings of the 2003 National Petroleum Council natural gas resource study, which found that 40 percent of the natural gas resource located in the Rockies, is either closed to exploration or faces severe restrictions on development.

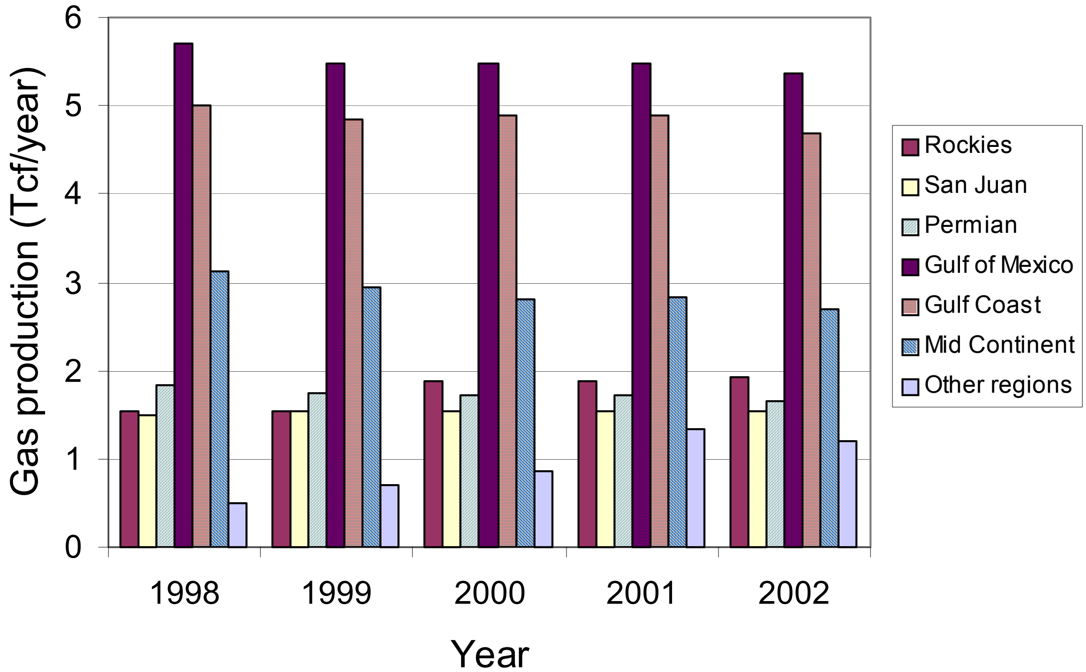

Figure 3.3: Natural gas production by region
Source CERA and EIA.

The category designated *other regions* is the combined production from smaller natural gas basins such as California, Upper Great Plains, Alaska, and Appalachia. The figure above reveals that during 1998–2002 production in the Gulf of Mexico, Gulf Coast, Mid Continent, and the Permian basin was declining, while production was holding steady in the San Juan basin. The Rocky Mountain basin and the smaller producing regions (*other regions*) showed some production growth during the period. Over the last several years U.S. natural gas production has held at roughly 19 Tcf per year.

As the Figure 3.3 above indicates, the Gulf of Mexico (GOM) is the nation's most important gas producing region contributing approximately 25 percent of U.S. gas production, or about 5 Tcf per year. Estimated reserves and undiscovered resources for the GOM are 56 Tcf. Recent deep-water discoveries (water depth greater than 1,500 feet and total depth more than 15,000 feet) have made up for declining discoveries and production from the shallow water Gulf. Figure 3.4 illustrates recent GOM gas production and the rapid rise in production from deep-water wells.

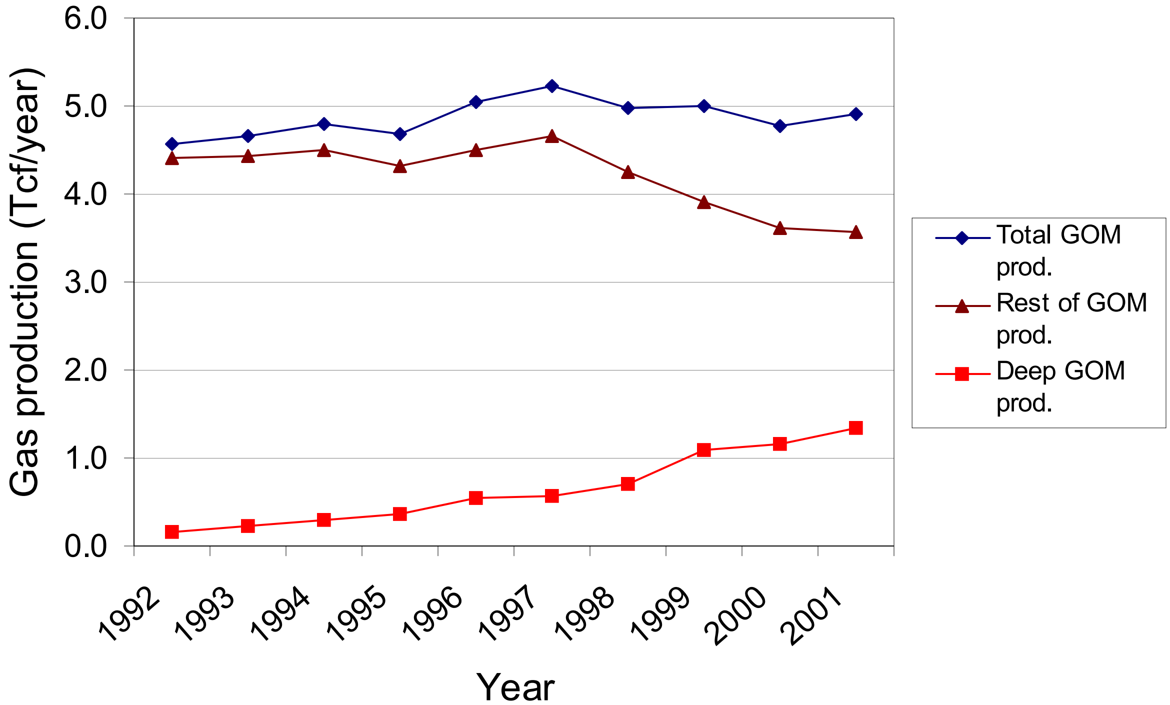

Figure 3.4: Gulf of Mexico production 1992-2001

Source: Michelle Michot-Foss testimony 2003.

Figure 3.4 illustrates how increasing production from deep-water GOM fields is just offsetting the decline in the rest of the GOM. Deep water drilling is much more expensive[27] and carries a higher risk penalty. Drilling for gas via ultra deep wells (total depth more than 15,000 feet) in the declining shallow water basins of the GOM appears to hold some promise, but is also expensive and risky. Over the next 10 years, only slight net additions to production from the GOM region are anticipated.

Mexican Production

Mexican natural gas production reached 1.75 Tcf in 1999, and has declined slightly over the last three years to 1.62 Tcf in 2002. Restructuring and privatization are taking place in parts of the natural gas industry and natural gas use in electricity generation and manufacturing has been encouraged. Demand for natural gas in the power generation and industrial sector has been forecast to grow by 14 percent annually (Alexander, 2002). Total Mexican gas demand is projected to grow 50 percent to 2.4 Tcf per year by 2010, and by 100 percent to 3.2 Tcf per year by 2015.

Mexican gas production and consumption is of importance to the Northwest, because Mexico has been unable to meet its internal natural gas requirements and has had to

[27] Average onshore drilling cost per well 0.5 million dollars; average deepwater well drilling cost 10 million dollars.

import increasing quantities of natural gas from the United States. The imported gas is primarily used to supply manufacturing facilities along the U.S. and Mexican border, and for electric power generation, some of which is sent north to U.S. consumers. The gas that Mexico imports is principally produced in Texas or New Mexico and is part of the resource available to California. A reduction in availability of this gas resource puts additional pressure on gas supply resources for California, including gas from the Rocky Mountain and Canadian regions. Indirectly, gas exports to Mexico put modest upward price pressure on gas resources supplying the Northwest. Near term projections are that exports to Mexico will continue to increase for several more years, reaching 750 Bcf/year in 2007 before liquefied natural gas (LNG) imports and Mexican production begin to fill market demand. Figure 3.5 below presents the U.S. natural gas exports from 1990 to 2002.

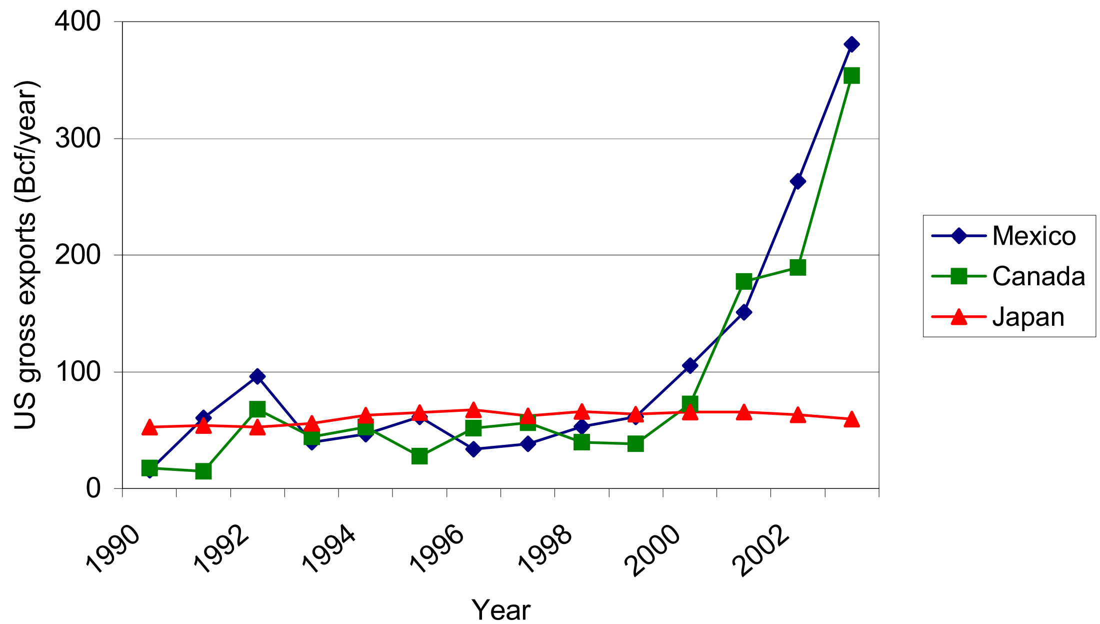

Figure 3.5: U.S. natural gas exports 1990-2002

Source: EIA.

As Figure 3.5 illustrates natural gas exports to Mexico and Canada have risen rapidly in recent years. Note that exports from Canada to the United States are more than an order of magnitude larger than exports from the United States to Canada. LNG exports to Japan via Alaska have been fairly steady at 60 Bcf/year. Though gas exports to Mexico are not yet significant (less than 2 percent of U.S. consumption), continued growth over the next several years could put additional upward pressure on U.S. natural gas prices. Because of Mexico's rapidly growing need for natural gas, several LNG projects have been proposed for Baja California and the Gulf of Mexico and are in the early stages of development.

Production from a Mature Resource Base

North American natural gas production and consumption grew rapidly from the late 1980s as the economy expanded and deregulation continued. By the late 1990s production growth had slowed as the excess productive capacity, developed primarily during the 1980s, was slowly eroded. For the last six or seven years U.S. producers have essentially run flat out all year round. See Figure 3.6 below.

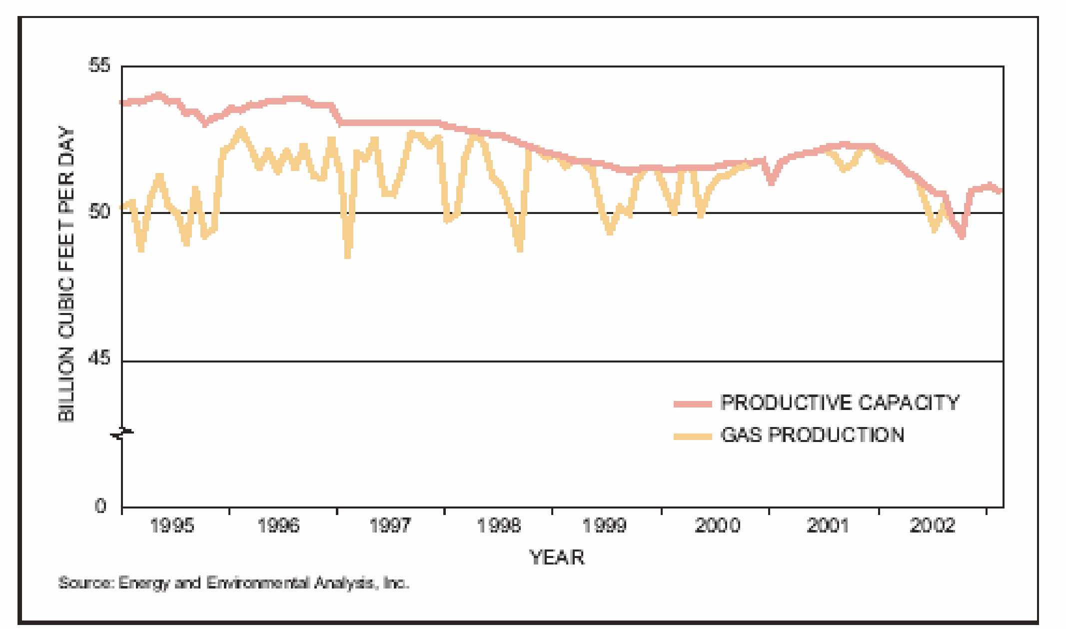

Figure 3.6: Lower 48 production versus productive capacity

Source NPC 2003

U.S. production peaked in 2001 following a ramp up in drilling that was induced by the high natural gas prices of 2000-01. A significant decline in drilling and a slight decline in gas production followed the natural gas price collapse of 2002. Decreasing recovery volumes and productivity per gas well, has meant that more wells have to be drilled every year just to keep production steady. Figure 3.7 below illustrates the decreasing average well productivity in the United States and the increasing number of active wells necessary to maintain or grow production. The addition over the last 10 years of progressively more gas wells with rapid decline rates (small gas fields) has increased the overall base decline rate of the North American gas resource from 17 percent per year in 1992 to 27 percent per year in 2001.[28] The NPC anticipates an average of nearly 20,000 gas well connections will have to be made each year from 2005 to 2020 just to maintain current production. The average number of new gas connections from 1986 to 1997 was only 6,950 per year.

[28] The increase in the base decline rate has been even more dramatic in Canada.

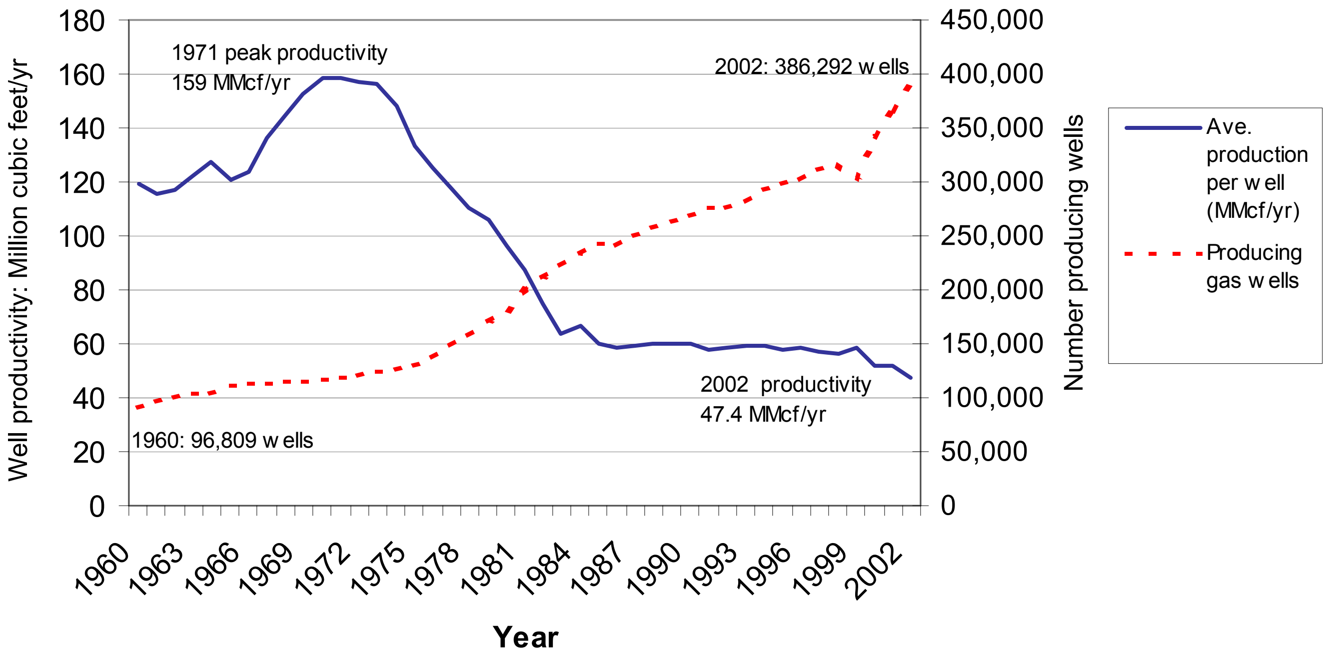

Figure 3.7: Number of producing wells in the United States and average productivity
Source: EIA.

As recently as three years ago the EIA and NPC forecast that significant new gas resources and productive capacity could be developed in the United States and Canada in response to small increases in gas wellhead prices. However, decreasing well recovery volumes (see Figure 2.2), reduced reserve appreciation factors, and a weak production response following the drilling boom of 2000-01 has caused both the NPC and EIA to reevaluated the future productivity of the U.S. Lower 48 and the Canadian natural gas resource.

The NPC now forecasts significantly higher prices and flat production through 2020 for the U.S. Lower 48 and non-Arctic Canada. Production from conventional gas basins will continue to decline, and will be offset by increases in production from unconventional gas resources. The EIA forecasts slightly lower prices and a small production increase for the U.S. Lower 48 and non-Arctic Canada through 2020.

Both the NPC and EIA now acknowledge that traditional resources, which include some unconventional gas resources, will not be able to meet the forecast increase in North American gas demand. New resources (and production) such as Arctic natural gas and LNG are included in sizable quantities in the newest NPC and EIA forecasts.

Summary

A review of production assessments and forecasts by the EIA, NPC and others allow us to make the following observations.

1. Canadian production after rising rapidly in the 1990s to 6.6 Tcf per year, appears to have reached a plateau and is unlikely to grow prior to the large-scale development of Arctic and unconventional gas resources.
2. Due to increasing internal natural gas consumption Canadian exports to the United States will be flat over the next five years and will likely decline after 2010.
3. Natural gas production from the Rocky Mountain basins is forecast to increase to 4.5 Tcf per year by 2020. While this resource is relatively close, the Pacific Northwest will have to compete with other gas consuming regions.
4. Most other gas producing regions in the United States have recently shown flat or slight declines in production. The deepwater region of the Gulf of Mexico is forecast to show a small production increase over the next five to 10 years.
5. Mexico has been unable to meet its growing natural gas demand and is importing increasing quantities from the United States. This puts additional pressure on gas markets in the U.S. Southwest.
6. The gas producing basins in the U.S. Lower 48 and Canada (excluding Arctic and Rocky Mountain regions) are mature and cannot meet the growing North American demand for natural gas. New resources will be necessary to meet growing demand and to avoid even higher gas prices.

Section 4: Future Natural Gas Supply and Production

Both the National Petroleum Council (NPC) and Energy Information Administration (EIA) have recently concluded that while traditional North American producing areas will be able to supply about 75 percent of the nation's gas needs in 2020, additional supplies and production will be necessary to meet anticipated demand. The two additional gas resources that are likely to contribute significantly to North American natural gas supply in the longer term are liquefied natural gas (LNG) and Arctic (Alaska and Northern Canada) natural gas.[29] Another potential future resource is natural gas hydrates, which are sometimes referred to as methane hydrates. This resource although potentially tremendous in size is much more speculative and is only discussed briefly.

Arctic Natural Gas

The Arctic regions of Alaska and Northern Canada contain significant amounts of natural gas resources. These gas resources were discovered over 30 years ago, but because of high transportation costs they have not been developed. The trend towards higher gas prices, which began in 2000, has made the development of the Arctic resources much more attractive.

Alaska

The Minerals Management Service (MMS) of the U.S. Department of Interior in 2001 estimated the Alaska natural gas resource base at 220 Tcf, 88 percent of which is undiscovered.[30] Some of the gas resource will not prove to be economically viable, residing in small fields, or in regions too remote for extraction. Most of the proven economical reserves are located onshore and offshore in Northern Alaska. A small amount is located in Southern Alaska at Cook Inlet where it is used for local consumption and as feedstock for a small LNG terminal were gas is sent to Yokohama, Japan. Some natural gas is consumed each year by the petroleum industry, but 85 percent of the gas that is extracted is re-injected into the oil fields to maintain pressure, and for future use.

The undiscovered gas resources are much larger (192 Tcf) than the discovered reserves, and are equivalent to roughly 40 percent of the estimated undiscovered conventional reserves in the Lower 48. Over time the assessment of the Alaska gas resource is likely to increase as the lack of a local market or export potential have limited exploration and geological surveying in Alaska. However, since the undiscovered resources are just that, undiscovered, estimating what fraction is economically recoverable is difficult. The MMS estimated that at $2/MMBtu only 6.2 Tcf of undiscovered natural gas is economically recoverable. The economically recoverable volumes increase to 12.2 Tcf and 35.8 Tcf at market prices of $3.35/MMBtu and $5.80/MMBtu respectively. At the higher natural gas prices experienced during 2003 and 2004 it is reasonable to assume that the current economically recoverable natural gas resource (proved reserves and potential resources) in Alaska ranges from 50 to 60 Tcf. Over time, technological improvements and continued

[29] Natural gas resources in Mexico are not well assessed and could potentially contribute significantly to North American supply.

[30] The NPC 2003 estimates the Alaska technical resource base at 331 Tcf using advanced technology.

exploration will most likely increase the economically viable Alaska gas resource and production potential.

Transport Options for Alaska Natural Gas

At this time Alaska natural gas is essentially stranded and will require a pipeline, physical conversion to LNG, or chemical conversion to some other type of liquid hydrocarbon in order to reach markets in the continental United States. The two likely pipeline options for accessing Alaska natural gas are discussed briefly below.

1. The most direct route is to build a line from Prudhoe Bay to the Mackenzie Delta project that is being developed by the Canadians. This would give the Alaska natural gas access to existing northern Alberta pipelines. Estimated cost is 10 to 15 billion dollars, and would require gas prices above \$3.5/MMBtu (MMS, 2001).
2. The alternative route, and the one favored by Alaskan politicians, would parallel the existing oil pipeline to Fairbanks, and then follow the Alaska highway towards Valdez, before heading southeast to the gas pipelines in northern British Columbia. Estimated cost is 17-20 billion dollars, and would require long-term gas prices above \$3.75/MMBtu (MMS, 2001).

Other options such as LNG liquefaction at a Southern Alaska port, or gas to liquid (GTL) transformation followed by transport on the oil pipeline has been considered but is currently too expensive. British Petroleum is currently experimenting with a small GTL unit on the North Slope.

While there have been several false alarms about Alaska natural gas becoming marketable it seems likely that federal support in the form of loan guarantees or price supports will result in one of the pipeline options being actively pursued within the next year. Alaska natural gas probably won't enter the market until 2013-15, but eventually would contribute 5 Bcf/day, or nearly 2 Tcf/year (8 percent), to North American supply.

Because of Washington State's proximity to Alaska and the gas pipeline systems in British Columbia and Alberta we can anticipate several benefits from development of Arctic natural gas resources. First, this ensures that a long-term supply of natural gas will be delivered to the regional pipeline system. In addition, construction and operation of the pipeline will require material and labor some of which will be supplied by Washington State. Finally, the project will require use of Washington State ports for transport of materials and personnel.

Northern Canada

Proven gas reserves in the Mackenzie Delta/Beaufort Sea area of Northern Canada are estimated at 9 Tcf. The potential resource is estimated at 55 Tcf, resulting in a total resource base of 64 Tcf (CERI, 2003). The pipeline required to develop the Mackenzie resource is currently in the planning stages and is expected to come into service by 2008-09 with an initial annual production volume of 0.6 Tcf (1.5 Bcf/day), expandable to 0.8 Tcf. Cost for the pipeline is estimated at 2 to 3 billion dollars.

The Mackenzie gas resource may not be a significant contributor to the North American gas supply because of the continued development of the Alberta oil sands.[31] A large amount of energy is required to extract and process the bitumen from the sand: 1 Mcf natural gas per 1.2 barrels of bitumen processed or 0.5 Tcf of gas per year for projected 2010 oil sands production (First Facts, 2003). In addition, natural gas liquids and light naphtha from conventional oil are required to further upgrade the bitumen into a synthetic crude that can be processed by Canadian or U.S. refineries.

Liquefied Natural Gas Imports

Meeting future U.S. natural gas demand will require not only aggressive development of new conventional, unconventional (coal-bed methane, tight sands, etc) and frontier gas resources in the United States and Canada, but also the rapid expansion of another gas source – imported LNG. In the spring of 2003, LNG made the headlines after Federal Reserve Chairman Alan Greenspan presented the fed's view to Congress on recent turmoil in the U.S. natural gas market, and the need for new gas supplies. Chairman Greenspan identified LNG as the most promising new source of natural gas, and anticipated that it would eventually be freely traded like petroleum, which would serve to dampen price volatility in the U.S. market.

LNG is one of the world's most rapidly growing fuels, accounting for 21 percent of all gas imports and exports (5.1 Tcf), and serving nearly 6 percent of worldwide natural gas demand in 2001 (PGC, 2002). LNG growth has averaged 6.4 percent per year over the last 20 years with most of the expansions being made in Asia. Energy analysts believe that in the next decade LNG will be freely traded like petroleum, and that daily spot market prices will be prominently listed.

In the United States, LNG is emerging as an important supplemental resource to meet growing U.S. natural gas demand. Worldwide proven reserves of natural gas were 6,076 Tcf in 2002 (EIA, 2004), and the total potential gas resource was estimated at over 13,000 Tcf. By comparison, in 2002 U.S. proven reserves were estimated at 188 Tcf (EIA, 2003) and Canadian reserves at 60 Tcf. World reserves are many times larger than North American reserves, but are often stranded far from market, in countries that have limited current or future need for the natural gas.

LNG process

The key components of the LNG process are: 1. Liquefaction; 2. Shipping; and 3. Regasification.

The first step is liquefaction where feedstock from the production gas field is taken to the liquefaction plant, where contaminants such as water, carbon dioxide and nitrogen are removed. The cleaned natural gas is cooled using large refrigeration units (called trains) until the gas liquefies at a temperature of –256 °F. The liquefaction process reduces the volume of the natural gas by a factor of 600, resulting in a product (LNG) that can be economically transported by ship.

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[31] The Canadian National Energy Board in its *Energy Market Assessment 2004*, estimated that synthetic crude oil production from the oil sands will slightly more than double between 2003 and 2015.

The next step involves loading the LNG onto a special tanker, which has several insulated double hulled stainless steel tanks that contain the super cooled LNG at atmospheric pressure. The tankers cost approximately $160 million, and can carry 2.6 to 2.8 Bcf of LNG (Institute for Energy, 2003). A small amount of LNG must be boiled off to keep the bulk of the LNG in its liquid form, and is used as fuel for the tanker's propulsion turbines. As of December 2002, there were 136 LNG tankers with 57 ordered for delivery by 2006.

The final step is converting the LNG back to a gas at a regasification facility. The LNG is pumped out of the tanker into a land based cryogenic container, then sent through several expansion chambers as it is warmed and converted into a gas. The natural gas is then either stored or enters a natural gas pipe system for delivery to customers.

LNG economics

Experience and economies of scale gained from the development of the East Asian LNG market have driven down LNG production costs in nominal terms by 30 to 40 percent over the last decade (Utilis, 2003). Gas liquefaction costs dropped from an average of $560/ton during 1986-1990, to $250/ton 1996-2000, while LNG vessel costs have dropped from $230 million to $160 million. Table 4.1 illustrates the improving economics of LNG.

Table 4.1: LNG component costs in 1995 and 2002

Cost component	Year: 1995 ($/MMBtu)	Year: 2002 ($/MMBtu)
Netbacks *	0.50	0.75
Pipelines	1.00	0.75
Liquefaction plant	1.25	1.00
Shipping	1.25	0.65
Gasification	0.35	0.35
Delivered to Market	4.35	3.50

Source: *Introduction to LNG*, Institute for Energy, Law & Enterprise, Jan. 2003.

*Netbacks are the return for the gas resource project developer.

Concerns over facility siting, regulations, and security within the United States may add slightly to the delivered gas costs shown above. In addition, West Coast costs will be somewhat higher due to longer transportation distances. Table 4.2 presents the NPC's estimates of long-term market prices, by location, at which LNG will becomes economically viable. With current technology, LNG imports should be viable when long-term Henry Hub natural gas prices exceed $3.25 to $4.0/MMBtu. LNG import costs are significantly lower at the four existing U.S. LNG facilities relative to estimated costs for new LNG regasification facilities. On the U.S. West Coast a long-term gas price in excess of roughly $4.5/MMBtu, would be necessary because the LNG must be transported significantly greater distances.[32] See Appendix B for estimated transportation costs from different producing regions. Over the long-term, the price at which LNG

[32] West Coast LNG would come either from Qatar, Indonesia, Australia, or possibly Bolivia. The latter would require an extensive pipeline to transport the gas to a Chilean port.

becomes economical will probably decrease slightly as production, liquefaction, transportation, and regasification economics continue to improve.

Table 4.2: Price at which LNG becomes economically viable

Facility Location	Trigger price (2001 $/MMBtu)
Everett, MA	3.42
Cove Point, MD	3.33
Elba Is., GA	3.23
Lake Charles, LA	3.41
New England	4.02
Florida	3.96
Washington/Oregon	4.53
California	4.26
Baja California, Mexico	3.32

Source: NPC 2003

LNG Safety

LNG has been handled safely for years. There are currently 12 countries with 17 liquefaction facilities that produce LNG (NPC, 2003). See Figures 4.1 and 4.2 on the next page for locations of existing and proposed liquefaction facilities. Over the life of the industry there have been eight marine accidents worldwide, but no fires, or catastrophic explosions, or shipboard fatalities. Isolated accidents and fatalities have occurred at terminals, most in the early days of the industry. The recent explosion at the Skikda natural gas liquefaction facility in Algeria will undoubtedly bring the safety issue to the forefront again. The Federal Energy Regulatory Commission (FERC) is currently evaluating LNG safety.

In the United States, one commercial LNG facility failed in operation, and caused catastrophic damage to Cleveland, Ohio, in 1944.[33] A shortage of high quality stainless steel during World War II led to compromises in LNG storage tank design, and consequently a storage tank failed and filled the streets and storm sewers of adjacent neighborhoods with natural gas. The vaporized LNG ignited and 128 people subsequently died. No cracks have been reported in the past 35 years with more modern tank designs. However, since that time, LNG facilities have been generally limited to more remote locations. There have been no catastrophic accidents in the United States involving LNG storage tanks since 1944. Industrial accidents, including fatalities, occurred at U.S. LNG facilities in 1973 and 1979, but were much more limit in damage and did not involve catastrophic tank failures. These accidents resulted in several design changes that have since been implemented industry wide (Institute for Energy, 2003).

The terrorist attacks of September 11, 2001, raised concerns about security risks at LNG facilities, particularly those located near large urban centers. Additional security measures will likely be necessary to minimize the potential terrorist threat at these sites.

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[33] From the *Encyclopedia of Cleveland History*, Case Western Reserve University: *The EAST OHIO GAS CO. EXPLOSION AND FIRE took place on Friday, 20 Oct. 1944, when a tank containing liquid natural gas equivalent to 90 million cubic feet exploded, setting off the most disastrous fire in Cleveland's history*

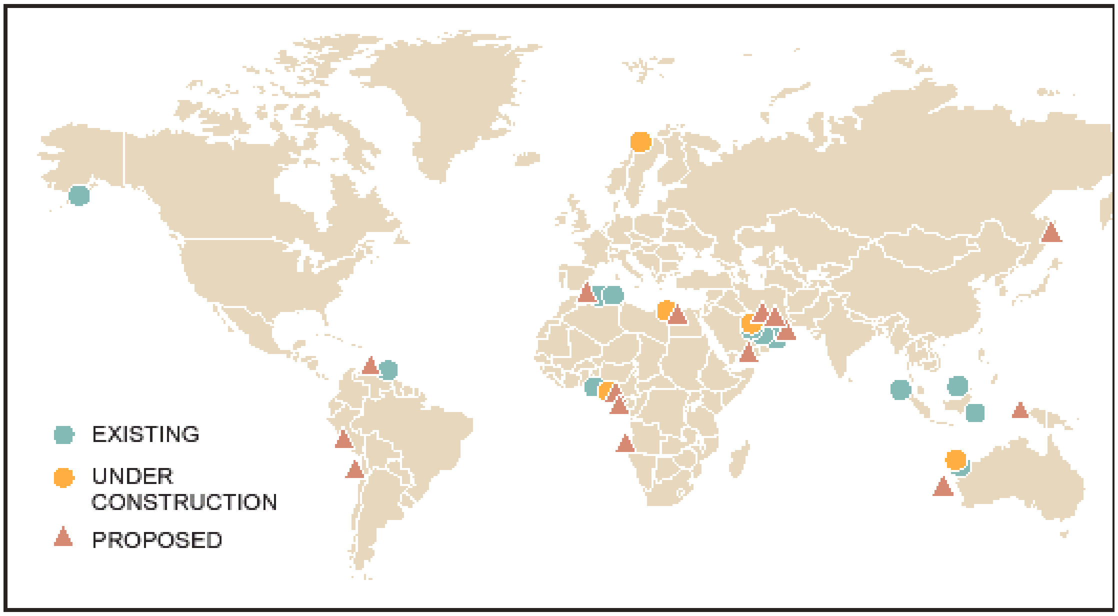

Figure 4.1: Existing and proposed LNG liquefaction facilities worldwide
Source: NPC, 2003

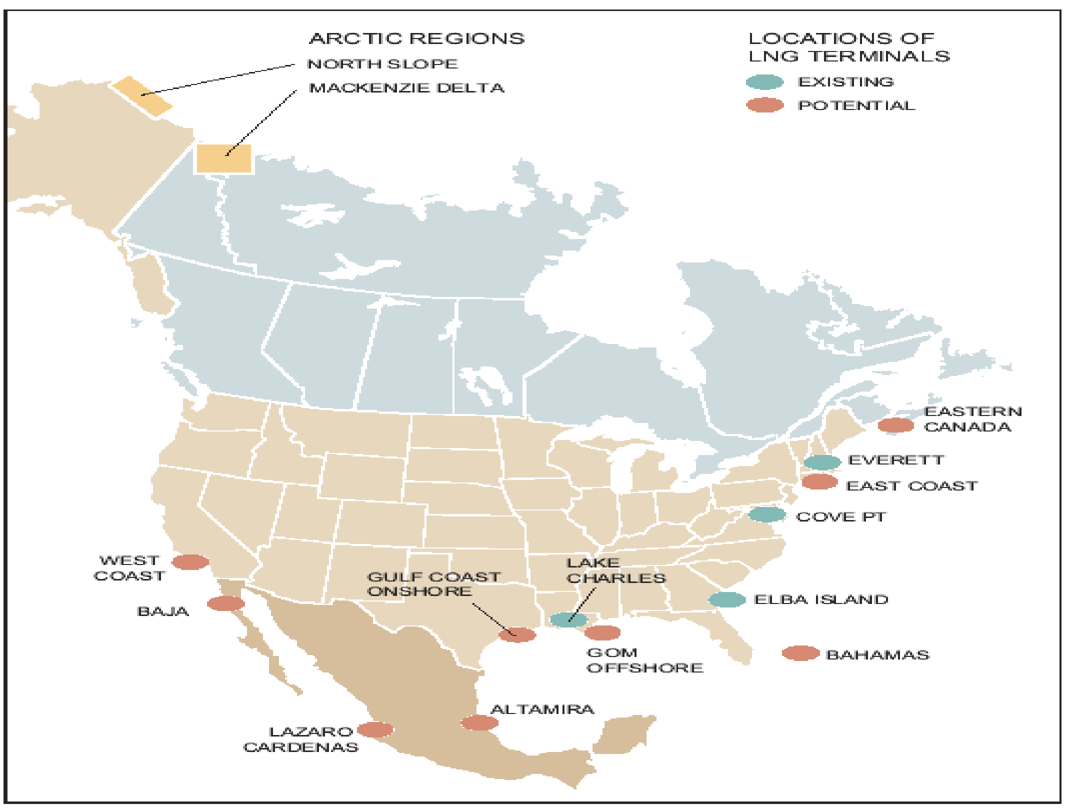

Figure 4.2: Existing and proposed LNG receiving terminals in North America
Source: NPC, 2003

LNG Facilities

The United States currently has four LNG receiving terminals located on the East and Gulf coasts. These terminals were designed and constructed in the late 1970s when regulated wellhead gas prices and a series of oil crises caused natural gas demand to exceed supply. Natural gas prices collapsed during 1983-85 as wellhead price deregulation continued and oil prices began to slide. Three of the four LNG terminals were mothballed and the fourth operated at minimal capacity during the 1980s and '90s. Following the run-up in natural gas prices in 2000-01, efforts were undertaken to reactivate and upgrade the terminals. The capacities and expansion plans for the existing LNG terminals are shown in Table 4.3 below.

Table 4.3: Current U.S. LNG facilities

Location	**Capacity (MMcfd)**	**Storage capacity (Bcf)**	**Expansion plans (MMcfd) (Bcf)**	**Owner or operator**
Everett, MA	435	5.5	600, ---	Distrigas
Elba Is., GA	440	6.4	360, 3.3 storage	Southern
Lake Charles, LA	630	10.1	590, 2.5 storage	CMS
Cove Pt., MD	1,200	8.5	---, 2.8 storage	Dominion

Maximum LNG delivery capacity is currently about 2.7 Bcf/day and with expansions will rise to 4.2 Bcf/day by 2007-08. Assuming a 75 percent capacity factor this could translate to deliveries of 2.0 Bcf/day with current capacity and 3.2 Bcf/day following the proposed expansions: Representing about 3 and 5 percent respectively of current average daily U.S. gas consumption. Limitations on the supply and transport components of LNG delivery will probably constrain market share development for several years. Over the long-term, LNG market share is anticipated to grow significantly: Utilis Energy forecasts more than 5 percent market share by 2008, while Cambridge Energy Research Associates (CERA) forecasts LNG taking 10 to 20 percent of the market by 2020.

Numerous sites in the United States, Canada, Mexico and the Bahamas are being considered for LNG import facilities. No LNG site development is being actively pursued in the Northwest. Siting in the United States may be particularly difficult due to state and federal regulatory restrictions and local opposition. For this reason, sites in Mexico and the Bahamas that can serve the U.S. market are also being considered. Offshore LNG degasification terminals are less controversial and are also being studied.

Considering the significant cost of developing LNG liquefaction or regasification facilities, project financing will be of major concern, and consequently most development work is being undertaken by the large international energy companies and their national energy company counterparts. These organizations have the personnel, experience and resources to pursue risky, but potentially highly profitable projects.

More than two dozen LNG projects have been proposed for North America over the last several years: See Appendix B for a current list. While many of the proposed projects are speculative and unlikely to be completed, several projects are likely to be completed as they are backed by major oil and gas companies and have advanced through the early permitting process. The major oil companies have an additional advantage in that all of them are involved in the other steps of the LNG development chain – remote natural gas field development and planning and construction of gas liquefaction facilities. For North America as a whole over the next decade, a reasonable conjecture is that two to four LNG facilities will be constructed on the Atlantic and Gulf coasts, and two to three on the Pacific Coast (Natural Gas Weekly, 2003). Combined with the four existing U.S. LNG facilities, the potential LNG contribution to the North American gas market is slightly more than 3 Tcf /year, or roughly 10 percent of anticipated demand.

In 2003, Cherry Point Energy LLC announced a proposal to develop a LNG facility in the Puget Sound region. The proposed facility is of modest size, 450-500 million cubic feet (MMcf)/day, and could in theory supply about 15 percent of natural gas needs in the Pacific Northwest (Forbes, 2004). Several utilities have expressed interest in the project. A facility site has not been selected yet.

A number of factors will influence the rate at which LNG gains market share in the United States. Some of these factors are listed below.

- Long-term perceived price of natural gas. Periods of low gas prices, as seen in 2002, will make LNG projects appear more risky to developers.[34]
- Lack of sufficient liquefaction facilities, transportation and regasification facilities and supporting infrastructure. For LNG to competitively enter the U.S. market the expensive and complicated steps described in the sections above must be completed concurrently.
- Overcoming the Not In My Back Yard (NIMBY) reaction. Local opposition to LNG regasification terminals will be significant and may delay or stop many proposed projects. Remote, offshore and industrial locations will have significant siting advantages
- Safety concerns will shape public opinion and project permitting,
- Balance of trade concerns. The United States currently runs a large trade deficit – importing significant quantities of LNG would add to the deficit.

LNG Contracting

Historically LNG contracting has been conducted on a long-term basis, with many contracts running 15 to 20 years. In the United States, the natural gas market has since deregulation evolved into a short-term market, with most purchases being made on the daily or monthly spot market. The differences in these two markets may present some difficulties for LNG market development. However, the LNG spot market does seem to be developing with 8 percent of traded LNG being purchased on the short-term market in 2002 (EIA, 2004). In addition to hedge against market volatility there is a trend in the U.S. gas market back to longer term contracts, which is a better match for the capital intensive LNG industry.

[34] Developers will require a risk premium, adding to the internal rate of return necessary to make projects viable.

Natural Gas Hydrates

Natural gas hydrates are solid, crystalline, ice-like substances composed of water, natural gas and other gases, and are formed at moderate pressure and reduced temperatures. The natural gas is trapped in the lattice like structure of the frozen water, and is released when the hydrate is warmed. Gas hydrates are found in permafrost regions and in ocean sediments at depths greater than 450 meters. The gas hydrate resource is immense, dwarfing all other hydrocarbon resources, with a central potential resource estimate of 742,000 Tcf. For comparison, the global potential resource of conventional natural gas is estimated at only 13,000 Tcf. The Alaska gas hydrate resource is estimated at 169,000 Tcf, with over 99 percent located in offshore regions.

Although gas hydrates are a vast potential resource, none are being commercially processed into natural gas. Japan and the United States have committed significant research money to developing the technology to commercially exploit the gas hydrate resource. The large-scale commercial extraction of natural gas from gas hydrates is not expected for at least 20 years.

Summary

Our review of the recent natural gas production statistics and forecasts prepared by the NPC, EIA, AEUB and various industry analysts allows us to make the following observations.

1. Artic natural gas has great production potential, (Alaska 5 Bcf/day, Northern Canada 1.5 Bcf/day), but is an expensive and risky resource to develop.
2. Development of the Arctic resources will take 10 to 20 years.
3. LNG is currently cost competitive in many parts of the United States, and has the potential to enter the gas market in limited amounts at four existing LNG receiving facilities.
4. By 2008, it is likely that capacity upgrades at the four existing LNG receiving facilities will be complete and in addition several new facilities will become operational, making additional LNG imports possible.
5. LNG trigger prices are slightly higher for the West Coast of North America.
6. The EIA forecasts that the United States will import 4.1 Tcf per year of LNG by 2020, representing nearly 14 percent of U.S. gas supply. In 2003, the National Petroleum Council forecast a 15 percent market share for LNG by 2020. A recent report by Cambridge Energy Research Associates (CERA) forecasts that LNG will take a 10 to 20 percent market share by 2020.
7. Over the next 5 years LNG imports will have a limited impact on North American natural gas prices. Ten or more years in the future LNG will have a more pronounced effect on gas prices and may prevent the development of marginal gas fields within the United States and Canada.[35]

[35] Energy analysts have speculated that development of an extensive LNG market in the U.S. will result in the long-term decline of the domestic natural gas exploration and production industry.

Section 5: Recent Supply and Demand Forecasts

Short-term supply-demand and price forecast

High gas prices during the summer and fall of 2003 were in part caused by the need to make up for the huge draw down of natural gas storage during the winter of 2002-03, which resulted in near record low gas storage levels. As storage levels climbed back into the five-year average range during the summer and fall of 2003, natural gas prices on the 2- to 24-month futures market gradually fell about 20 percent from the peak levels in May and June 2003. A combination of reduced demand and incremental supply increase accounted for the improved gas storage and price situation in late 2003. Moving into 2004, a recovering economy and high oil prices put some upward pressure on gas price.

The Energy Information Administration (EIA) forecast that U.S. production would rise by 1 to 2 percent in 2003 and by about 1 percent in 2004 and 2005.[36] Demand was estimated to be down 3 percent in 2003 relative to 2002, and forecast to rise about 2 percent in 2004 and 1 percent in 2005. The EIA forecasts a continuing tight balance between supply and demand through 2005, which is corroborated by the natural gas futures market where gas is being bought and sold at around $5 to $6/MMBtu through 2005.

Long-term supply forecasts

For this report we reviewed the five national natural gas supply studies shown below.

1. National Petroleum Council (1999): *Natural Gas – Meeting the Challenges of the Nation's Growing Natural Gas Demand.*
2. Energy Information Administration (2001): *U.S. Natural Gas Markets – Mid-term Prospects for Natural Gas.*
3. California Energy Commission (2003): *Preliminary Natural Gas Market Assessment.*
4. National Petroleum Council (2003): *Balancing Natural Gas Policy - Fueling the Demands of a Growing Economy.*
5. Energy Information Administration (2004): *Annual Energy Outlook 2004.*

The supply forecasts span the time frame from late 1999 to early 2004, a period that includes two significant gas price spikes and the West Coast energy crisis. The forecasts rely on many of the same data sources,[37] differing primarily in the dates when the data was assembled. Model design, scenario criteria, and assumptions do differ between the forecasts. Of particular interest is how the North American supply and price forecasts have evolved over the five-year period covering the reports. A brief summary of each report is provided below.

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[36] Lehman Brothers in their quarterly survey of gas producers estimated a 1.6 percent decline in 2003 U.S. production and forecast a 1-2 percent decline in 2004 (Natural Gas Week, Feb. 16, 2004). EIA recently saw their forecast of a 2 percent production increase for 2003 evolve into to a 0.5 percent actual increase.

[37] All of the reports rely on data from the GPC, USGS and MMS for their analyses. In addition the CGPC and NEB provide some of the information on Canadian resources and production. Several energy-consulting firms also provide information and modeling input.

National Petroleum Council (1999): *Natural Gas – Meeting the Challenges of the Nation's Growing Natural Gas Demand.*

The NPC noted that during the 1990s gas demand growth had outpaced the central estimate of their 1992 natural gas report. The more rapid growth in gas demand was attributed to the higher than anticipated economic growth rate of the 1990s, the competitive price of natural gas, and its clean burning attributes. Natural gas demand at the national level was forecasted to grow to 29 Tcf in the year 2010, and 31.3 Tcf by 2015. Growth in electric power generation was predicted to account for 47 percent of the increase in gas demand.

Technological advances, an adequate supply of skilled workers, and more drilling rigs, were seen as necessary to continue development of more difficult non-conventional gas resources. Increased access to natural gas reserves in restricted areas was also seen as critical to supply growth.

Energy Information Administration (2001): *U.S. Natural Gas Markets – Mid-term Prospects for Natural Gas.*

The first section of the EIA report focused on recent growth in natural gas demand and the marked run up in gas prices during 2000-2001. The report cited high gas demand in 1999-2000, low gas storage levels,[38] and a cold winter as the principal causes of the 2000-2001 natural gas price spike.

The EIA forecast total gas supply being 31.7 Tcf in 2015. U.S. production[39] was projected to be 26.3 Tcf in 2015, with a market price of 3.07 $/MMBtu (2000 dollars). The EIA report examined the possible impact of several critical factors on natural gas supply and price. These factors included rapid resource depletion,[40] access limitations to gas resources on federal lands, a national carbon dioxide emission limitation, and variable LNG costs.

California Energy Commission (2003): *Preliminary Natural Gas Market Assessment*

The CEC report focuses on the West Coast and was developed as the most recent natural gas price spike began to emerge in late 2002. This report had a noticeably different tone from the earlier gas supply reports, but predicted that supplies of natural gas, though more costly, would be sufficient through the 2003 to 2013 time frame that CEC examined. Growth in U.S. gas production was forecast to be incremental, and it was expected that the nation would become more reliant on Canadian natural gas imports and possibly LNG.

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[38] The EIA reported low storage levels at the end of the refill season – 2,732 Bcf at end of October, the lowest level since 1976. A cold winter drew the already low storage down to a very low 742 Bcf by the end of the 2000-01 heating season

[39] EIA forecasts no significant increased production from Alaska until 2018.

[40] Aspects of the rapid resource depletion scenario were incorporated into the EIA's *Annual Energy Outlook 2004* report.

Market volatility, due to the close balance between gas supply and demand, would result in occasional price spikes and potential demand destruction in the industrial sector.

Natural gas supply for the United States was projected at 29.4 Tcf in 2013 with 21.8 Tcf from U.S. production with an average wellhead of $3.71 (year 2000) in 2013.

National Petroleum Council (2003): *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy.*

In response to the recent spike in natural gas price the energy secretary in March of 2003 asked the National Petroleum Council to update its 1999 natural gas supply and demand market assessment and make summary findings available by October 1, 2003. The 2003 NPC natural gas report begins by acknowledging that the gas market had fundamentally changed since the 1999 report, and that a wide range of policy actions would be necessary to maintain adequate supplies and keep natural gas prices at an acceptable level. The NPC presented "Reactive Path" and "Balanced Future" scenarios. The Reactive Path assumed a continued tight balance between gas supply and demand due to policies that promoted consumption and limited production. Gas prices for this scenario remain in the $5 to $6/MMBtu range, which as a consequence reduces long-term natural gas demand.

The Balanced Future was the preferred scenario and emphasized action in the following policies areas to moderate prices.

- **Demand reduction**: Greater emphasis on efficiency and conservation, both in direct use of natural gas and in electricity. Some demand destruction will continue in the industrial sector as energy intensive industries relocate outside of North America.
- **Supply growth**: Increasing access to U.S. resources that currently cannot be developed. Promote development of large-scale resources such as LNG and Arctic natural gas.
- **Infrastructure**: Promote timely development of infrastructure and reduce regulatory and financial barriers to establishing long-term gas contracts.
- **Markets**: Promote development of physical and risk management tools to moderate the effects of price volatility.

Under the Balanced Future scenario, annual U.S. demand is forecast at just under 27 Tcf in 2015, with approximately 21 Tcf coming from U.S. production, including over 1.5 Tcf coming from Alaska via pipeline (completion in 2013-14). Wellhead prices are forecast to be in the high $3 to low $4/MMBtu range.

Energy Information Administration: *Annual Energy Outlook 2004.*

The EIA introduced its *Annual Energy Outlook 2004* report by noting that over the last four years natural gas prices had remained substantially higher than during the 1990s and had significantly exceeded previous EIA near term forecasts for the 2000-04 period. Accordingly, the EIA stated "this has led to a reevaluation of expectations about future trends in natural gas markets, the economics of exploration and production, and the size of the natural gas resource." Building on similar baseline data used by the NPC, the EIA made a large downward revision from its 2001 U.S. natural gas supply forecast.[41] The EIA 2004 *Annual Energy Outlook* forecast U.S. supply at 28 Tcf in 2015 with U.S. production[42] contributing 21.7 Tcf. The 2004 EIA forecast represents a 12 percent reduction in U.S. consumption and a 20 percent reduction in U.S. production relative to the 2001 forecast. Average wellhead price was forecast to be $4.14/MMBtu in 2015.

The U.S. supply forecasts presented in the five reports are summarized in Figure 5.1 below.

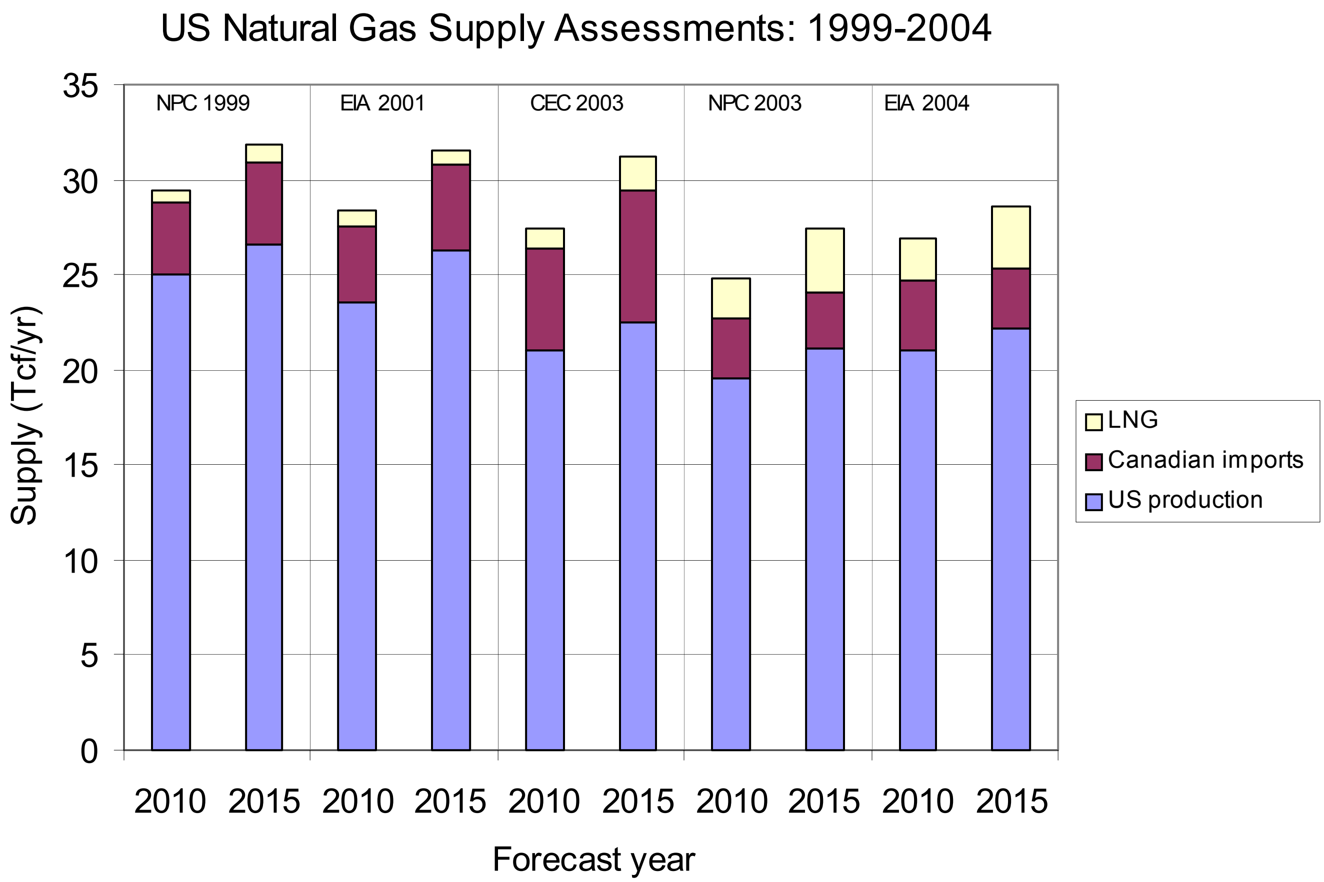

Figure 5.1: Summary of natural gas supply forecasts for 2010 and 2015

* CEC 2008 and 2013 supply and price values extrapolated to 2010 and 2015. Note that some combinations of production and imports don't add up to total supply, as exports to Japan and Mexico are not included.

Supply and Demand Reassessment

Over the last several years there has been an evolution in the supply (production and imports) forecasts produced by the EIA, NPC and other entities. The early NPC (1999) and

[41] The EIA also made an initial downward revision for U.S. gas supply in the 2003 *Annual Energy Outlook*.

[42] No significant Alaska production in the EIA supply forecast: Pipeline completion date estimated as 2018.

EIA (2001) reports are similar, both forecasting significant increases of approximately 40 percent in overall supply and U.S. production during the 2000 to 2015 time period. Within a year after its release the 1999 NPC report came under considerable criticism for underestimating demand growth, particularly in the power generation sector, and for overestimating future productive capacity in the conventional U.S. gas basins (Natural Gas Weekly, 2003).[43]

As Figure 5.1 above illustrates, the 2003 NPC and 2004 EIA reports represent a significant reassessment of the North American natural gas supply outlook. The NPC natural gas study shows a large downward revision in forecasted natural gas supply relative to the earlier NPC report: Forecast annual U.S. demand in 2015 is reduced by approximately 4 Tcf, while the forecast for total U.S. gas production is diminished by nearly 5.5 Tcf. Even more remarkable is that the forecast for Lower 48 production in 2015 has been reduced by more than 6.5 Tcf/year in the more recent report. Canadian production forecasts were also diminished in the 2003 NPC report.[44] The NPC report also makes an upward revision in forecasted gas prices, drilling activity, and the volumes of future LNG imports. The revisions between the 2001 and 2004 EIA reports for U.S. supply and production are similar to the revisions made by the NPC. Figure 5.2 below further illustrates the recent downward revision in the forecasted natural gas production for the Lower 48.

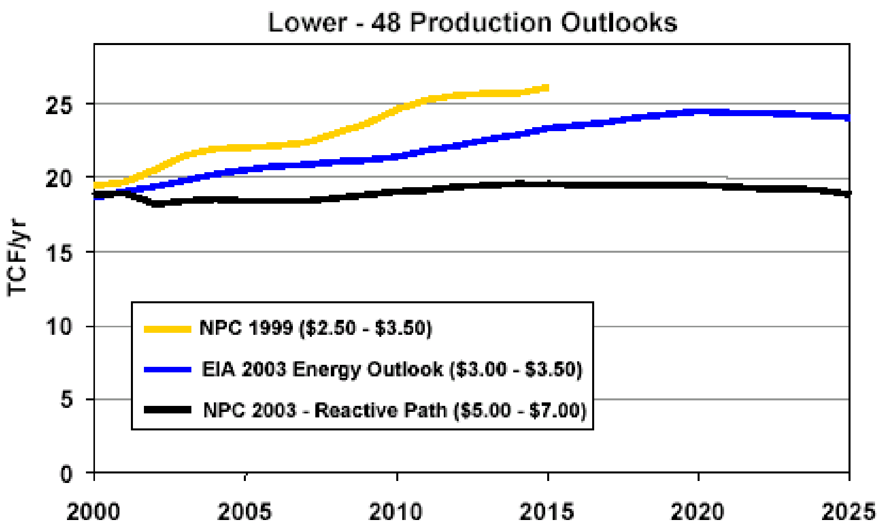

Figure 5.2: Reassessment of future Lower 48 natural gas production NPC, 2003

The EIA in its 2003 and 2204 *Annual Energy Outlook* (AEO) reports has significantly reduced the forecasts for total U.S. gas supply and production relative to the 2001 EIA report. The AEO 2004 report presents a 2015 forecast with overall gas supply revised

[43] The 1999 NPC report forecast an additional 2.7 Tcf/year of production from the Gulf of Mexico, while a more recent analysis by the Minerals Management Service (MMS) forecast a 1.7 Tcf/year decline in production by 2010.

[44] The 2003 NPC Canadian production forecast of 6.6 Tcf/year is about 10 percent lower than in the 1999 report. Evidence supporting the lower forecast came from the CGPC, the NEB, and the AEUB.

downward by 3.7 Tcf/year, U.S. production diminished by 4.7 Tcf /year, and LNG imports increased by 2.4 Tcf/year. In addition, the AEO 2004 wellhead price forecast for 2015 has been increased by $1.1 /MMBtu. Figure 5.3 below compares EIA forecasts for U.S. supply and production from the five most recent AEO reports (AEO 2000-2004). The figure clearly illustrates the EIA's recent downward revisions in forecasts for U.S. supply and production, as well as Canadian gas imports. By contrast forecasts for historically more expensive sources of natural gas supply such as Arctic gas[45] and LNG imports are substantially higher in the most 2004 AEO report.

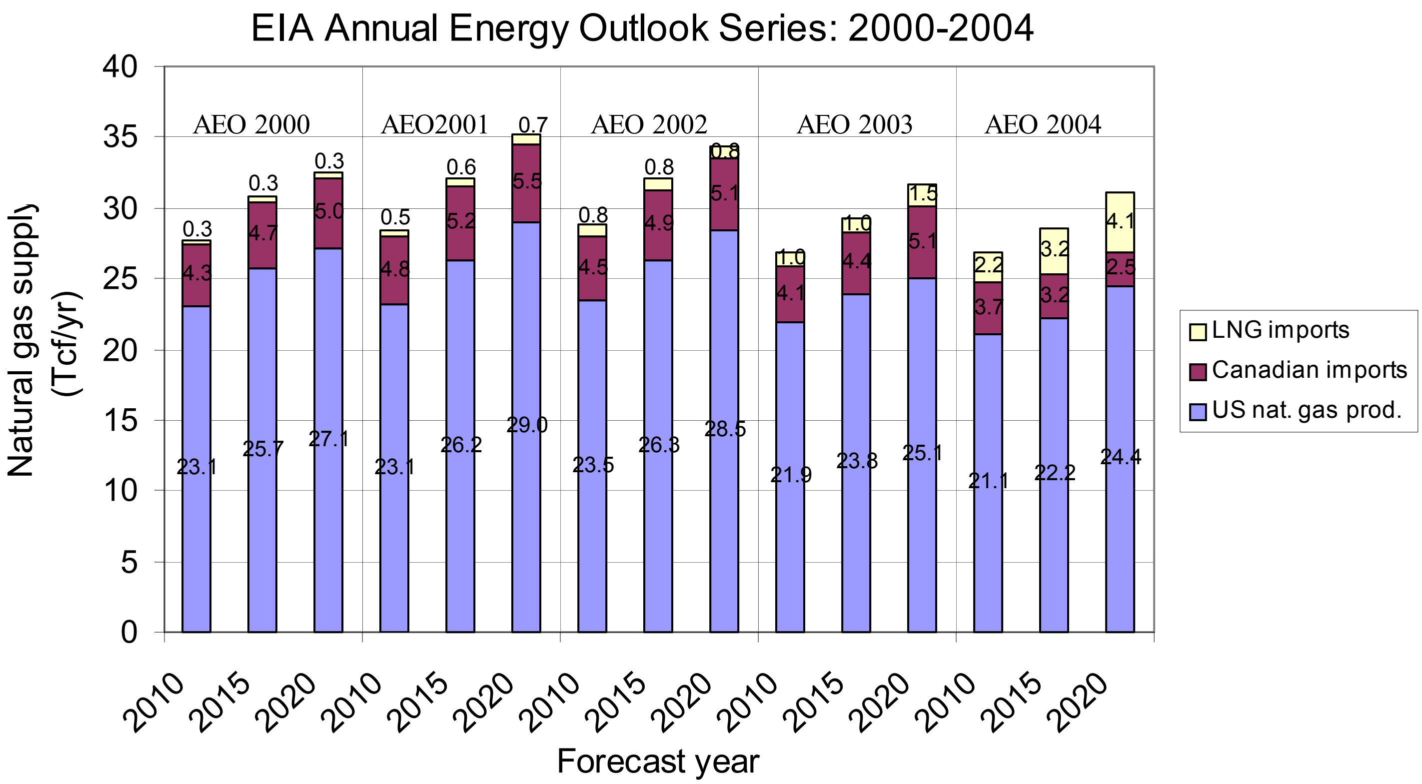

Figure 5.3: EIA Annual Energy Outlook natural gas supply forecasts

Reasons for Recent Reductions in North American Supply Forecasts

A number of factors contributed to the difference in supply and U.S. production forecasts between the 1999 and 2003 NPC reports. The four most critical factors were:

- A lower assessment of the technically recoverable resource base; see Section 2 for details. The primary factors leading to the reduction in assessed resource base were a lower reserve appreciation factor, a reduction in the ultimate recovery volume for undiscovered fields, and a slightly lower estimate of the unconventional gas resource base;[46]
- The weak marginal production response to the price/drilling run-up of 2000-01;

[45] In the 2004 EIA analysis, 4.5 Bcf/day of Arctic gas enters the market in the 2016-2018 time frame.

[46] Lower relative to EIA assessments.

- The rapidly maturing resource base, manifested by rapidly increasing well decline rates, and diminishing ultimate recovery volumes for new wells;
- A small net reduction in the forecasted technology improvement factor in the 2003 report.

Long-term Demand Forecasts

From 1985 to about 1997 the North American natural gas market was demand limited, in other words there was enough spare production capacity to meet growing demand and to handle sudden increases in demand caused by periods of extreme weather. During this period prices were generally low and stable. From 1997 to 2000 North America transitioned to a supply limited natural gas market where supply and demand were tightly balanced. Excess production capacity became minimal and consequently prices have tended to be higher and more volatile.

The 1999 NPC and 2001 EIA supply and demand reports[47] forecast that only minor increases in price would be necessary to induce the development of significant new gas supplies. The two reports predicted continued strong growth in demand for natural gas, particularly in the power generation sector, through 2020. Essentially the NPC and EIA were forecasting the continuation of a demand limited natural gas market.

The "reassessment" of natural gas supply by the NPC and the EIA in 2003 and 2004 signaled the official acknowledgement[48] of the shift to a supply constrained market: See Section 2 for discussion of supply reassessment. The recent reassessment of U.S. supply has had a dramatic effect on demand forecast. The impact of constrained supply is particularly dramatic on the forecasts for the power generation and the industrial sectors.[49] Figure 5.4 below presents the NPC and EIA sector demand forecasts for 2010 and 2015. For the year 2015 forecast, the EIA reduced its estimate of natural gas demand by 10 percent in the industrial sector and by nearly 20 percent in the power generation sector.[50] Residential and commercial demand forecasts were revised downward only slightly. The NPC also made significant revisions in the sector demand forecasts between the 1999 and 2003 reports. Forecast demand for 2015 was reduced by 15 percent in the power generation sector and by 25 percent in the industrial sector. The 2003 NPC report essentially forecasts no demand growth in the industrial sector over the next 10 to 15 years.

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[47] In the 1990s energy consultants such as GRI also forecast robust growth in U.S. supply and demand

[48] Energy analysts such as Andrew Weisman (Energy Ventures Group), Mathew Simmons (Simmons & Company), and Daniel Yergin (CERA) gave warnings of changes in the natural gas market since 2001.

[49] Often when energy intensive businesses are faced with high gas prices they either switch fuels or relocate offshore.

[50] Comparing the AEO 2004 to the AEO 2001 report.

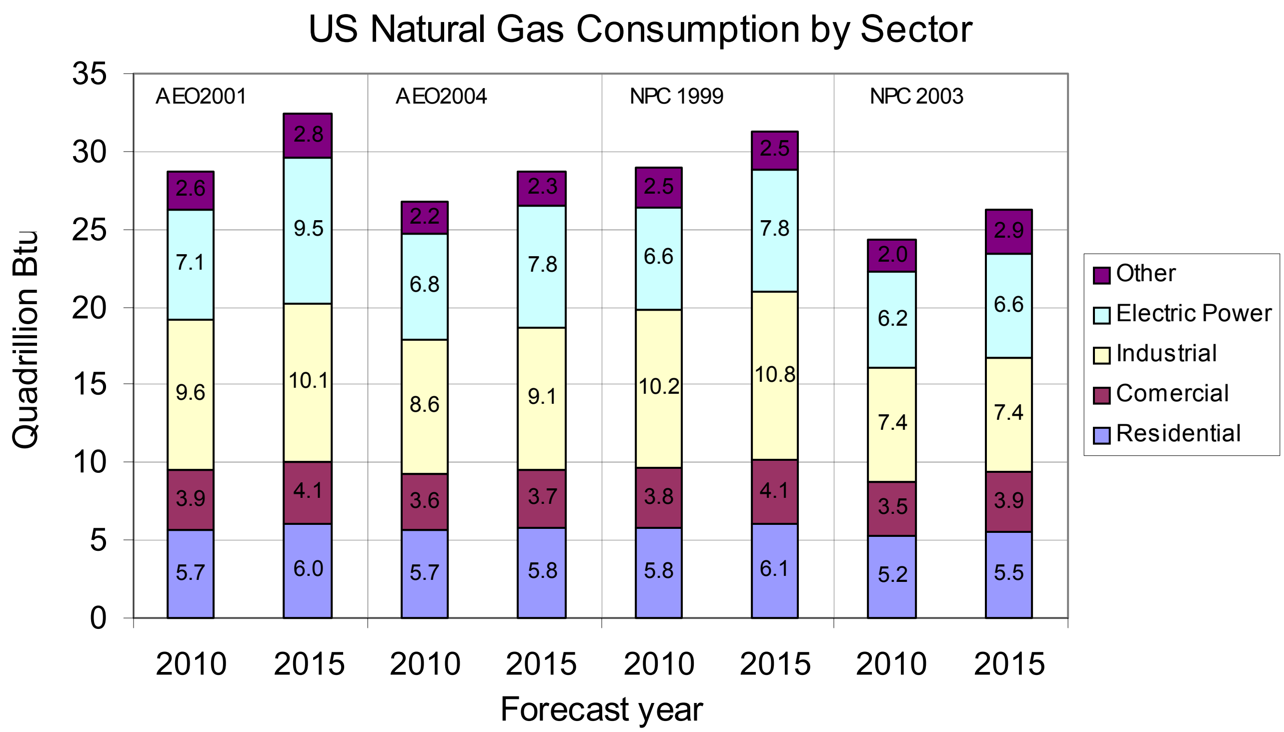

Figure 5.4: EIA and NPC 2010 and 2015 forecasted natural gas consumption by sector

Demand Forecast for the Pacific Northwest

The California Energy Commission (CEC) recently completed its *Natural Gas Market Assessment* (CEC, 2003), which was prepared as part of the CEC *Electricity and Natural Gas Report*. The primary focus of the natural gas market assessment was California, but the CEC also analyzed demand growth in the Pacific Northwest and for all Western states as defined by the Western Electricity Coordinating Council (WECC).

The CEC used the North American Regional Gas (NARG) model as its principal assessment tool. NARG is a general equilibrium model that predicts the prices (at five year intervals) necessary to balance supply and demand for a given scenario. The CEC released a draft of the *Natural Gas Market Assessment* in 2002 and a final report in August of 2003. Changing electricity and natural gas market conditions during the period 2001 through 2003, made it necessary for the CEC to update the demand forecast. Table 5.1 below illustrates the demand forecasts derived using the NARG model in 2002 and 2003.

Table 5.1: CEC Natural gas demand growth forecasts for 2003-13

Forecast →	2003 demand (Tcf)		2008 demand (Tcf)		2013 demand (Tcf)		Annual growth 2003-13	
Region and Sector	2002 report	2003 report	2002 report	2003 report	2002 report	2003 report	2002 report	2003 report
Pacific Northwest								
Electricity	0.17	0.18	0.27	0.23	0.42	0.27	9.15%	3.96%
All other sectors	0.46	0.42	0.50	0.45	0.49	0.48	0.51%	1.51%
Subtotal	0.63	0.60	0.77	0.67	0.90	0.75	3.56%	2.31%
California								
Electricity	0.66	0.80	0.74	0.89	0.82	0.93	2.22%	1.54%
All other sectors	1.61	1.40	1.79	1.46	1.94	1.50	1.87%	0.67%
Subtotal	2.27	2.20	2.52	2.35	2.76	2.43	1.98%	0.99%
Western States								
Electricity	1.23	1.46	1.70	1.93	2.12	2.03	5.60%	3.36%
All other sectors	2.98	2.61	3.33	2.78	3.59	2.93	1.88%	1.16%
Total	4.21	4.07	5.04	4.71	5.71	4.97	3.10%	2.00%

Source: CEC 2003

Table 5.1 illustrates several interesting points about the 2003-2013 West Coast natural gas demand forecasts. First, there has been a sizable reduction in the forecasted demand growth between the CEC's 2002 and 2003 analyses: 3.1 percent overall annual demand growth is reduced to 2 percent for the Western states region. The relative decrease in demand growth is even larger for the electrical generation sector: 35 percent *relative* reduction in the forecast of overall gas demand growth versus a 40 percent *relative* reduction in the electrical generation sector demand growth. Note that the reduction in the 2003-13 forecast for Pacific Northwest annual electrical generation demand growth, which was reduced from 9.15 to 3.96 percent, is the largest. This drop in demand growth is in part attributable to the permanent loss of the aluminum smelting industry, which was not fully factored into the 2002 report. Finally, the share of West Coast natural gas consumption devoted to electrical generation is forecast to rise considerably over the next 10 years from 29 percent of consumption in 2003 to 41 percent of consumption in 2013. For the Pacific Northwest, gas consumption in the electrical generation sector rises from 27 percent to 36 percent of overall gas consumption.

Summary

The EIA and NPC have recently revised downward their natural gas forecasts for U.S. supply and production. The EIA revised estimated supply and demand for year 2015 down by 11 percent, U.S. production down by 18 percent, and LNG imports upward by nearly a 280 percent. The NPC revised year 2015 supply down by 16 percent, U.S. production down by 26 percent, and LNG imports upward by nearly 270 percent. The primary reasons for the significant changes in the supply and production forecasts are:

1. A lowered assessment of the technically recoverable natural gas resource base;
2. Weak marginal production response to the price/drilling run up of 2000-01;
3. Mounting evidence that the North American gas resource base is mature, and growth potential is limited;
4. The gas resources replacement cost is more than assumed in the earlier studies;

5. LNG is now price competitive with domestically produced natural gas in many parts of the United States.

Downward revisions in forecast U.S. demand parallel the downward supply and production revisions. The largest revisions are in the industrial and power generation sectors. Part of the forecast reduction in demand is due to price induced efficiency and conservation. Demand destruction accounts for much of the reduction in industrial sector demand growth.

The CEC recently re-evaluated its natural gas demand growth forecast for the West Coast, including the Pacific Northwest. For the Pacific Northwest, the forecast gas demand growth in the electrical generation sector was decreased by more than 50 percent, while overall gas demand growth was reduced by 35 percent.

In hindsight, the early NPC (1999) and EIA (2001) natural gas reports were overly optimistic about the expansion of United States and overall North American natural gas supply. They may have had the unfortunate effect of encouraging higher levels of current and planned future consumption on the basis that natural gas would remain a plentiful and relatively inexpensive energy source. This may be especially true in the power generation sector where utilities and developers between 1998 and 2004 have added over 200 Giga-watts of gas-fired generating capacity at a capital cost of over 100 billion dollars. These optimistic reports, which forecast ample supply and low gas prices from 2000 to 2015, may have also delayed by many years the development of what were then thought to be uneconomical natural gas supply sources such as LNG and Arctic natural gas. The "rosy" gas supply scenarios put forth by the NPC and EIA may also have delayed development of what have now become cost competitive renewable and efficiency programs.

Section 6: Natural Gas Prices, Volatility, and Forecasts

Components of Natural Gas Price

An array of different natural gas prices are encountered in the media. Care must be taken when comparing gas price histories or forecasts that the same category of natural gas is being compared. The most common categories of gas prices are:

- Wellhead price - what the producer can get in the producing areas. This price varies by region, and is often expressed as a weighted U.S. or Canadian average.
- Beginning of interstate pipeline price - slightly higher than wellhead price as it includes costs for gathering and conditioning of the natural gas. Typical cost addition relative to wellhead price of \$0.15/MMBtu.
- End of interstate pipeline price - includes a transportation charge. Typical cost addition for transportation of \$0.45/MMBtu.
- Trading hub spot price - Henry Hub in Louisiana is the most frequently cited. The closest regional hub is at Sumas, Washington. Hub price is dependent on market conditions.
- City gate price – usually located in large metropolitan areas such as Chicago, New York or Los Angeles. City gate price is dependent on market conditions.
- Customer prices - include utility distribution costs and vary between residential, commercial, power generation and industrial sectors. Typical delivery cost addition of \$0.25/MMBtu for electricity generators, \$0.45/MMBtu for industrial customers and \$2.5/MMBtu for commercial and residential customers.

The natural gas prices most frequently used in forecasting reports are wellhead and trading hub prices. The differences in the costs shown above primarily represent the value of transportation and gas services. The recent higher wellhead and trading hub gas prices are often referenced to historical prices of the 1990s and are expressed as a percent increase. Note that a 100 percent increase in wellhead price (i.e. from \$2.5 to \$5.0/MMBtu) does not translate into an equivalent percentage increase for consumers due to the fixed transportation component of the final delivered product. A 100 percent wellhead price increase might translate into an 80 percent price increase for electricity generators and a 40 percent increase for residential consumers. The California Energy Commission estimated the price differentials presented above in 2003.

Recent Price Volatility in the Natural Gas Market: 2000 – 2003

For much of the 1990s wellhead and trading hub natural gas prices remained around the \$2/MMBtu range, though there was evidence that prices were moving up towards the end of the decade. By mid 2000 prices had moved past \$3/MMBtu as the result of increased demand following several years of sustained economic growth, which had reduced spare natural gas productive capacity. In the winter of 2000-01 two additional factors combined to sharply increase natural gas prices. On the West Coast a crisis in the electricity market had emerged, triggered in part by energy deregulation and market manipulation in California, and worsened by a drought that reduced hydroelectric generating capacity. To make up for the reduced hydroelectric power on the West Coast, thermal generation units, primarily gas fired, were called on to run more frequently resulting in increased gas consumption. The second factor was a colder than normal winter in the rest of the nation that followed on a series of mild winters, leading to additional residential and commercial demand for natural gas.

After two or three months of higher prices, natural gas drilling activity began to increase and soon thereafter gas production also began to rise. More importantly, mild weather, fuel switching, and a rapidly deteriorating economy resulted in reduced demand for natural gas. Prices fell back to early 1990s levels of $2 to $3/MMBtu and storage inventories were rapidly rebuilt achieving a five-year high by October of 2002. Some observers believed that increased supply, the result of higher gas prices and more drilling, had driven prices back to their traditional range. This optimistic view conveniently overlooked the significant reduction on the demand side, the result of a mild winter (2001-02), industrial fuel switching, and the recession that began in late 2000. Between April 1, 2001, and March 31, 2002, U.S. natural gas demand declined by roughly 2 Tcf (9 percent) relative to consumption in the prior 12 months (Weismann, 2003).

During the middle of 2002, oil prices began to rise as oil worker strikes in Venezuela, and tensions in the Middle East began to escalate. Low gas prices and higher prices for petroleum fuels caused some industrial users that switched fuels in 2001 to switch back to natural gas, boosting natural gas consumption and putting some upward pressure on gas prices. A slightly colder than normal winter heating season during 2002-03 in much of the country and a modest economic recovery resulted in a slight up tick in demand for natural gas. More importantly the brief return to low gas prices resulted in a drastic reduction in exploration and drilling in the United States and Canada. Because of the rapid production decline rates exhibited by new gas wells and the continued declines in the wells located on older large gas fields, production slipped noticeably during late 2002 and early 2003.[51] Despite entering the 2002-03 winter heating season with natural gas storage inventories at the high end of normal (3,185 Bcf), production and inventory draw downs were *nearly insufficient* to carry the nation, particularly the East Coast, through a winter that had only 3 percent more heating degree days than the composite 30 year average.[52] In fact the winter of 2002-03 produced the largest gas storage draw down ever recorded: 2,530 Bcf over the course of the heating season. Just as the rapid rise in gas storage inventories heralded the natural gas price collapse of late 2001, the rapid draw down of inventories starting in late 2002 and continuing through April 2003 was a signal to the market that natural gas was once again in short supply and prices rose accordingly.

The pattern of weekly storage levels for the Lower 48 region, West, East and producing sub regions is shown in Figure 6.1. The winter of 2000-01 resulted in low gas storage levels (beginning from a low peak storage in November of 2000), and was more severe on the West Coast because of the drought and California energy crisis. The winter of 2002-03 gas storage draw down was particularly severe for the East Coast and the

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[51] U.S. dry gas production declined from 19.6 Tcf in 2001, to 19.0 Tcf in 2002 (EIA, *Short-term Energy Outlook*, 2003).

[52] At the end of the winter heating season gas inventories were drawn down to 642 Bcf, the lowest level in the 10 years since the EIA began tracking storage (EIA historical storage data).

producing regions. On the West Coast and in the Pacific Northwest, the winter of 2002-03 was mild and consequently gas storage remained sufficient. However, over the last decade or two, natural gas has to a large degree become a national commodity that can be readily exchanged between consuming sub regions. Thus a significant gas shortage and consequent high prices in one part of the country can induce higher prices in other parts of the country.

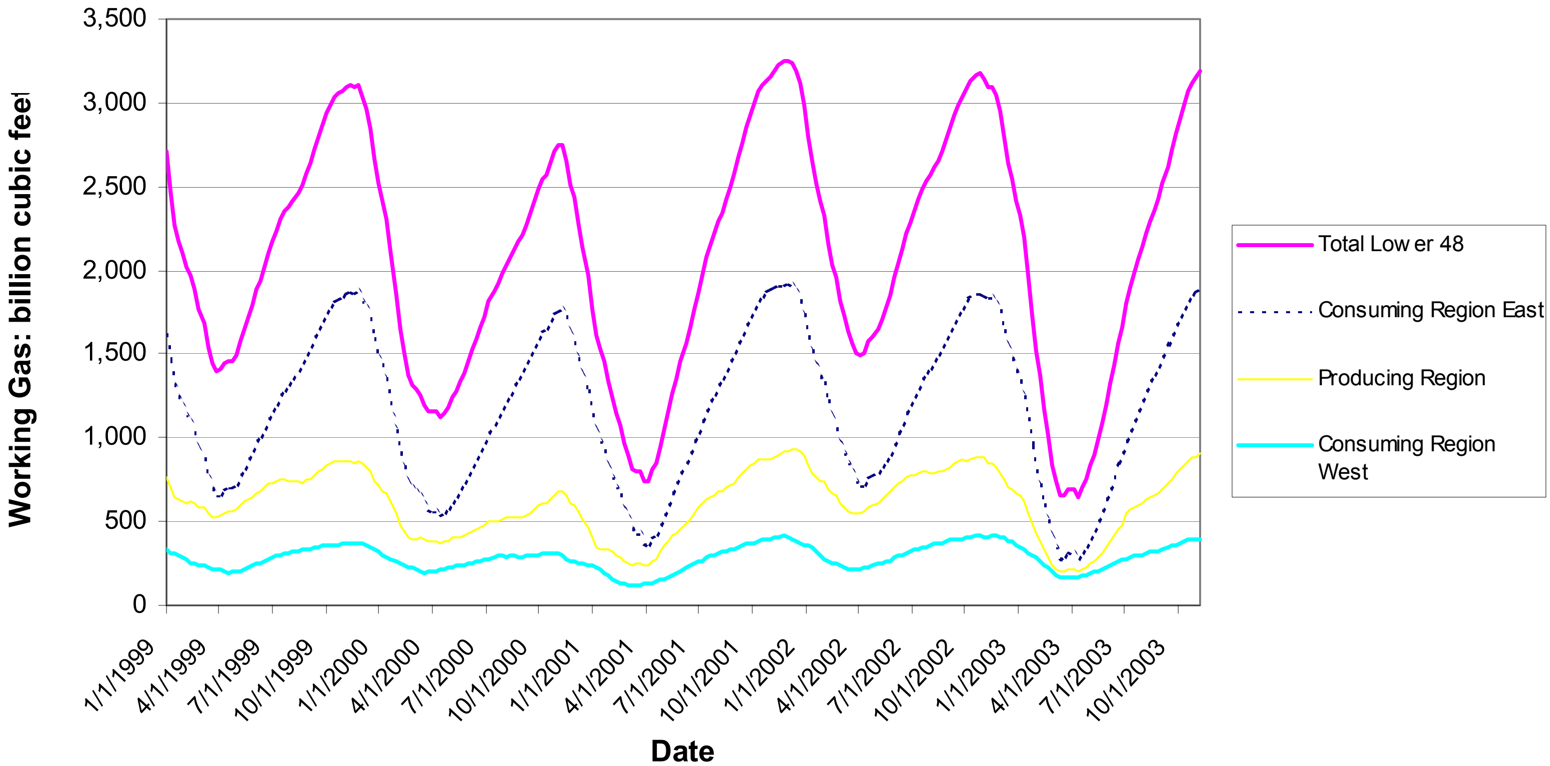

Figure 6.1: Weekly U.S. Natural Gas Storage: 1999-2003
Source: EIA

Supply Limitations – Primary Cause of Recent Natural Gas Price Volatility

While there were similarities between the conditions that lead to the 2000-01 and 2003 natural gas price spikes (slightly colder winters, increasing reliance on gas-fired electrical generation), there was also a significant difference. In late 2002 and early 2003, the U.S. economy was close to being in a recession, while in 2000 the economy, though slowing, was still quite robust. Despite the fact that industrial demand was significantly reduced in late 2002 relative to 2000, a second run up in gas price occurred. The underlying cause of the second gas price spike was lagging North American gas production.

The initial natural gas price spike in 2000-01 was the first overt sign that the North American gas market had entered a period of supply limitations and consequently a period of higher prices and price volatility. Because of a drought on the West Coast, manipulation in the energy markets by Enron and other marketers, and a cold winter for the eastern part of the nation, it was easy to ignore the warning implicit in the initial gas price spike. While a poorly designed electricity market in California and insufficient federal oversight of energy markets in general may have contributed to the 2000-2001 increase in gas prices, the underlying cause was primarily rooted in a gas market where supply was unable to meet demand. The second price spike during the slightly colder than average winter of 2002-03, occurred despite a period of reduced economic activity and convinced most observers that gas supply constraints for the North American market would remain for at least the next five years, and possibly longer. During this period, gas prices will be highly dependent on the severity of the weather, particularly during the winter, the level of economic activity, and whether industrial gas demand continues to decline due to fuel switching, efficiency gains and demand destruction (businesses failing or relocating). Continued rapid growth in gas-fired electrical generation capacity also has the potential to significantly impact mid-term and long-term natural gas prices.

Key Drivers of Natural Gas Price and Volatility

In a natural gas market where supply and demand are in tight balance several factors can influence price and volatility. These factors are discussed below.

Weather

Weather can have a significant impact on daily and monthly natural gas consumption and consequently short-term natural gas prices. During the coldest months of winter average consumption exceeds 80 Bcf /day.[53] Summer gas consumption averages only about 45 Bcf/day, while average supply (U.S. production and imports) is about 62-64 Bcf/day. A colder winter, such as that of 2000-01, can significantly increase daily demand and cause prices to jump dramatically on the daily and month ahead spot markets. Hot summer days increase air-conditioning and electricity demand, which in turn increases demand for natural gas-fired electricity generation. Currently, high summer gas demand does not tax the U.S. gas supply and infrastructure systems to the same degree that increased winter demand does.[54]

Drought and/or Reduced Snow Pack

Hydroelectric generation is the source of much of the electricity used in the Western United States and Canada. The Pacific Northwest is particularly dependent on hydroelectricity. Drought years, such as 2001, result in substantial reductions in hydroelectricity capacity.[55] Natural gas-fired generating units make up the shortfall in hydroelectricity, which puts upward pressure on natural gas prices for all users.

The mountain snow pack acts as a giant reservoir for the Pacific Northwest hydroelectricity system. Low snow pack can occur in non-drought years, reducing the amount of hydroelectric generating capacity, and necessitating additional generation from thermal resources including natural gas-fired generating units. Over the long-term,

[53] Extremely cold days can bring daily consumption to over 100 Bcf.

[54] However, high summer gas demand can result in significant reductions in storage injections for winter use, which will lead to increases in gas price and volatility.

[55] Hydroelectric production on the Federal Power System in 2001 was 45 percent less than production in 1997 and 40 percent less than 1999 (4,000-5,000 aMW deficit).

global warming is expected to reduce mountain snow pack and strain the hydroelectricity generating system on the West Coast.

Natural Gas Storage Levels

For about four months of the year (typically December through March) natural gas U.S. consumption exceeds the amount available from production and imports. During this period, natural gas storage is used to make up the supply deficit. Using gas storage as part of the supply system moderates prices and minimizes interruptions to consumers. Because on a national level, natural gas is a freely traded commodity, buyers and sellers closely watch not only the amount of gas in storage, but also the rate at which gas is added or withdrawn from storage. Abnormally high or low storages levels, or high or low injection or withdrawal rates of gas, can signal future supply-demand imbalance thereby influencing spot and forward market prices. High storage levels during the winter of 2001-02 in part caused low short-term gas prices, while low storage levels during the spring of 2003 in part caused high short-term gas prices.

Oil Prices

Historically, many industrial and utility customers have had the ability to switch between natural gas and petroleum fuels depending on prices. Higher oil prices in the early 1980s were in part responsible for the elevated gas prices seen during this period. During the late 1980s and 1990s low oil prices may have reduced natural gas prices and volatility. During the recent price spike of 2002-03 it became evident that gas prices had to some degree become decoupled from petroleum prices.[56] Two factors have allowed natural gas and oil prices to decouple: First because of more stringent air quality regulations there is now very limited fuel switching capability in the U.S. economy; second, natural gas supplies in North America are constrained and cannot be supplemented by imports.

Inelasticity of Natural Gas Supply and Demand

The current North American gas market has little excess production capacity (see Figure 3.6), which means short-term increases in natural gas demand are very inelastic.[57] In other words it is very difficult to bring new supply on line to replace lost production, or to meet increases in demand and/or price. Short-term supply inelasticity has contributed to the natural gas price volatility of the last several years. Over the long-term (two to 10 years), supply is generally more elastic as new supplies (unconventional gas, Arctic supplies, LNG, etc) can be developed. These new sources of natural gas can serve to dampen price volatility.

Short-term natural gas demand is also relatively inelastic. In the residential, commercial, and the electrical generation sector short-term natural gas demand is relatively inelastic; That is consumption does not change markedly as price increases or decreases.[58] Over

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[56] An old rule of thumb was that Henry Hub natural gas should be priced at just over \$1/Mcf for each \$10 of West Texas Intermediate price. Current oil prices would allow natural gas at about \$3.5/MMBtu, roughly 40 percent lower than actually observed.

[57] Price elasticity = percent use reduction (increase) / percent price increase (reduction)

[58] Residential and commercial consumers are insulated from short-term changes in gas price by regulatory processes, and consequently do not change consumption when spot market prices increase.

the long-term, natural gas demand is more elastic and will respond to sustained high prices. The National Energy Modeling System used by the U.S. Department of Energy and others uses short-term price elasticities of -0.24 to -0.28 and long-term values of –0.33 to -0.51.[59] Following a sustained gas price increase, demand will be gradually reduced as a result of efficiency upgrades, which take the form of new appliances or equipment, and conservation, which generally refers to behavioral changes such as reduced use of heating, cooling and lighting.

The industrial sector differs from the three sectors mentioned above in that its short-term natural gas demand is slightly more responsive (more elastic) to price increases. Industrial price-demand responsiveness takes two forms. The first comprises efficiency and conservation efforts, such as upgrading equipment or shifting production to more energy efficient equipment and some behavioral changes. The second form of natural gas demand reduction includes temporary fuel switching that some industrial operations are capable of on relatively short notice. During the natural gas price spikes of 2001 and 2003 a significant number of industrial gas consumers switched to distillate or residual oil.[60]

Pipeline Capacity

Although the North American pipeline network is extensive and provides sufficient capacity for most demand requirements, there are locations that can become constrained during periods of peak winter demand. These constraints show up as larger than normal price differentials between the main hubs in producing regions and city gate hubs in the consuming regions. Price differentials reflect the value of transporting gas between regions and provide incentives for new pipeline capacity additions as well as new supply additions. Periodically there has been a significant price differential between the Opal, Wyoming, gas hub in the producing region of the Rockies and the distribution hubs of Blanco, New Mexico, and Malin, Oregon: Two important gas hubs that service the California market. These price differentials were in part caused by pipeline capacity limitations during peak demand periods.

Lack of Reliable Information

The EIA publishes weekly and monthly information on natural gas supply, demand and storage. However, much of the information is lagged by six or more months, and is based partially on estimates out to 18 months. In addition the EIA frequently revises its most recently released information. The information time lag and revisions cause uncertainty for both producers and consumers alike, and contribute to price volatility. An example of this problem occurred during the recent gas spike in the spring of 2003, when the EIA frequently revised estimates of weekly storage withdrawals. Another government entity, the National Oceanographic and Atmospheric Administration (NOAA), also contributed to the information uncertainty when it initially reported that the winter of 2002-03, during which gas storage was drawn down dramatically, was slightly warmer than average. This information may have caused gas marketers to over

[59] A larger negative number indicates more price elasticity of demand: A value of –1.0 indicates that a 10 percent price increase results in a 10 percent reduction in demand.

[60] High petroleum prices in 2004 have probably stopped and may have reversed some of the fuel switching.

estimate the supply shortfall. NOAA subsequently reevaluated its data and portrayed the winter as slightly colder than average.[61]

Factors that Mitigate Price Volatility

A number of factors can work, alone or in combination, to reduce natural gas price volatility. These factors are briefly discussed below.

Sufficient Gas Storage

Gas storage is used routinely to smooth out supply and demand imbalances, particularly during the winter heating season. As noted above, excess gas in storage during and after the winter of 2001-02 caused prices to decline and remain relatively low and stable for the following six months. Regulators, suppliers and the Federal Energy Regulatory Commission (FERC) can work to ensure that sufficient gas storage is available and strategically located.

Fuel Switching

Fuel switching, or fuel substitution, is a means by which businesses that use large amounts of fossil fuel can mitigate high costs for a particular fuel. Fuel switching is not only a valuable option for industrial gas consumers, but for society as a whole since removing even a small fraction of industrial gas use can result in a noticeable price drop that also benefits commercial and residential gas consumers as well. Fuel switching capability essentially makes demand response to price more elastic in nature.

Fuel switching is primarily limited to older gas-fired power plants and boilers. Newer gas-fired power plants and boilers are designed to run almost exclusively on natural gas.[62] Analysts estimate the fuel switching potential at 2 Bcf/day (Michot-Foss, 2003). Though small, a reduction in consumption of 2 Bcf/day (equivalent to a few percent) can have a marked impact on short-term prices in a tight market. Figure 6.2 below illustrates the price points at which plant shutdowns or fuel switching occur, and the estimated volume of daily gas usage that is avoided. Price point estimates were made based on $20/barrel oil: Higher oil prices, as observed in early 2003 and 2004, will move the shutdown or fuel switching price points outward (to the right).

[61] An initial evaluation of the winter of 2002-03 indicated 2 percent fewer Heating Degree Days (HDD) than an average winter, while the re-evaluation put the number of HDD at 3 percent more than normal.

[62] Newer power plants and boilers have air pollutant emission constraints that prevent them from converting their equipment to run on distillate fuel.

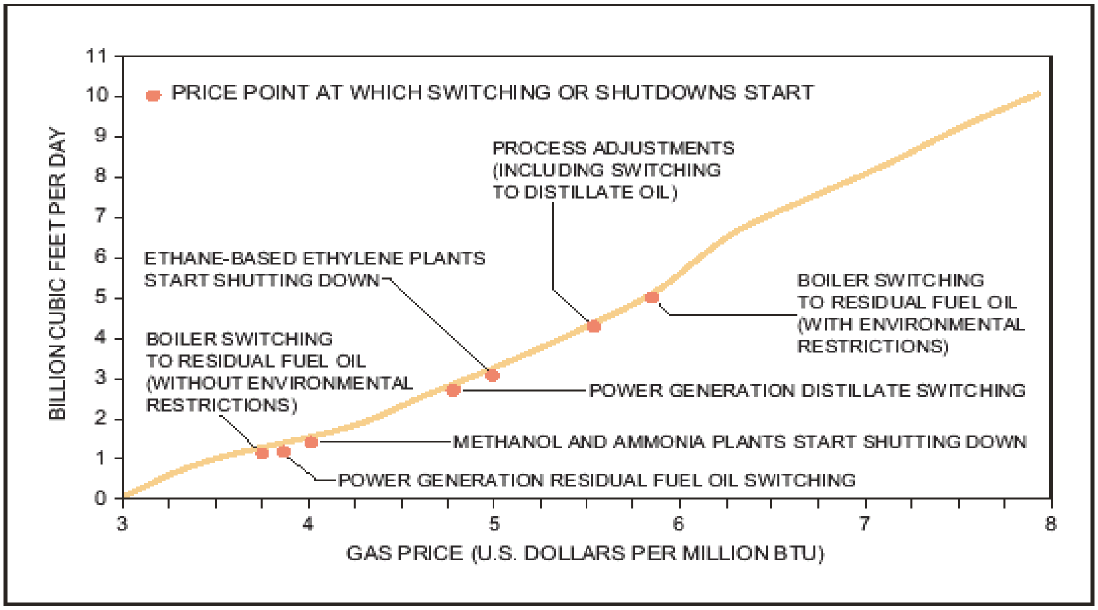

Figure 6.2: Industrial and power generation natural gas flexibility
Source: NPC, 2003.

In the past, the ability to fuel switch between natural gas and distillate or residual oil insulated the nation from petroleum or natural gas supply shocks. As petroleum derived fuels have been displaced by natural gas from use in the residential, commercial and particularly the industrial sector we have lost much of the flexibility of fuel switching.

Excess Production Capacity or Supply

The current natural gas market is supply constrained, with very little excess production capacity. Excess production capacity, which was available from 1985 until 1997, allows supply to respond quickly to modest increases in demand or price. Developing excess production or supply would moderate price volatility.[63] In the long-term, ten or more years, LNG will serve as the excess supply for the U.S. gas market. To effectively utilize excess production capacity there must also be sufficient pipeline capacity.

Long-term Contracting and Financial Hedging

Following market deregulation there has been a gradual transition from long-term to short-term contracts. This worked out well for industrial and Local Distribution Companies (LDCs) during the 1990s when short-term market prices were low and relatively stable. Recent market volatility seems to be providing an incentive to engage in longer-term contracts once again. Unfortunately many LDCs and industries are not financially sound enough to develop favorable long-term contracts.

Residential and most commercial gas consumers are served by LDCs at regulated rates, which are adjusted on a forward basis periodically to account for changes in market price. The current high and volatile prices have caused many LDCs to seek physical or financial

[63] Natural gas supply would become more elastic with respect to price.

hedging opportunities. Industrial customers are also using gas price hedging techniques more frequently.

Timely and Reliable Information

As discussed above time lagged and inaccurate information can lead to volatility in the natural gas market. The EIA, FERC and private companies that monitor the natural gas markets are taking steps to improve the information that is available. The FERC has recently investigated and penalized several marketing firms that misrepresented natural gas sales during the California energy crisis.

Conservation and Efficiency

Industrial, commercial and residential users will respond to high natural prices by pursuing short-term conservation and efficiency improvements. In the commercial and industrial sectors efficiency measures would include replacement or upgrading of older natural gas equipment (heaters, boilers, etc.), while in the residential sector efficiency measures would consist of switching to more energy efficient heaters and appliances. It is estimated that short-term efficiency measures can reduce natural gas consumption by 0.3 to 0.5 Bcf/day (Michot-Foss, 2003).

Conservation measures are more behavioral in nature and result primarily in temporary reductions in natural gas usage. Conservation efforts would occur in all sectors and include reducing heating demand in the winter by lowering thermostat settings, and reducing electricity used to meet air conditioning requirements in the summer. Short-term conservation efforts have the potential to reduce natural gas consumption by 0.5 to 1.5 Bcf/day, or 0.8 to 2.4 percent (Michot-Foss, 2003).

Reductions in Natural Gas Price and Volatility by Demand Destruction

Although demand destruction is not a desired outcome it does serve to reduce both upward pressure on gas price and volatility. Demand destruction typically refers to the temporary or permanent shuttering of operations in the most energy intensive industries, and often involves the relocation of the industrial operation to another country where energy (natural gas, electricity, etc.) is significantly less expensive. Usually there are multiple factors (labor costs, market access, regulations, etc.) that cause a business to relocate an industrial operation, making it difficult to assess the level of demand destruction that is solely the result of higher energy prices. Figure 6.2 above illustrates the price points at which some energy intensive industries shut down or switch fuel and the associated amounts of natural gas involved with these actions.

The fertilizer industry synthesizes ammonia and urea, which are frequently combined with other key ingredients to make fertilizer. Natural gas can account for 90 percent of the cost of producing ammonia; so high natural gas prices directly impact the price of fertilizer, and the competitiveness of the U.S. industry. Recent high natural gas prices have caused 20 percent of fertilizer plants to permanently shut down and another 25 percent to idle their production (Knight Ridder, 2003).[64]

[64] Demand destruction during 2000-03 in the fertilizer industry represents slightly more than 0.6 Bcf/day or 1 percent of U.S. natural gas consumption.

The chemical industry manufactures chemical precursors such as ethylene, propylene and methanol, which are used primarily by the chemical and plastic manufacturing industries to form more complex compounds. In response to high oil prices, much of the American chemical industry switched to natural gas for its feedstock and energy source in the production of these precursor chemicals. Since 2000, the industry has been at a competitive disadvantage because of high North American gas prices. It is unclear how much production has been lost due to high natural gas prices, but anecdotal evidence suggests that several plants have closed and a number of others have curtailed operations.

The Northwest has few fertilizer or chemical businesses and will not be significantly impacted directly. However, farmers and manufacturers that buy or sell products from or to these industries will be impacted by higher gas prices.

Extent of Recent Fuel Switching and Demand Destruction

While it is difficult to directly estimate the reduction in natural gas usage caused by current high prices, there is anecdotal evidence to support claims of at least a 5 percent reduction in gas demand. In recent testimony before the United States House Energy Committee information was presented that indicated a reduction in demand of 3 to 6 Bcf/day, equivalent to roughly 5 to 10 percent of average daily U.S. natural gas consumption, could be anticipated (Michot-Foss, 2003). Energy analysts Andy Weismann of Energy Ventures Group and Ron Denhardt of Strategic Energy & Economic Research, Inc., suggest that following the 2000-01 natural gas price spike, demand was reduced by 6 Bcf/day, with a 2 Bcf/day reduction from fuel switching, and the rest due to mild weather, and the recession of 2001-02.

Economic Consequences of High Natural Gas Prices

Sustained high natural gas prices reduce economic output and growth. The Industrial Energy Consumers of America (IECA) recently sent Congress a report on the financial impact of the “gas crisis” that began in June 2000. The report noted that while gas prices had averaged $2.37/MMBtu in the 41 months prior to June 2000, they had averaged $4.34/MMBtu in the subsequent 41 month period: representing an 83 percent increase. The direct cost to consumers of the higher gas prices over 41 months was calculated at $111 billion.

However, the IECA report didn’t take into account the extra earnings that higher gas prices represent for energy exploration and production (E&P) companies: The $111 billion in excess consumer costs are not a true loss to society, but rather a transfer of wealth to energy companies, many of whom are domestic. A large fraction of the transferred wealth ends up as dividends or earnings for shareholders or goes to support increased employment at the E&P companies. On the other hand the IECA report didn’t take into account indirect costs due to reductions in savings and investment opportunities for individuals or businesses, or plant shutdowns and relocations. These later effects represent true losses to our society from higher gas prices.

While a considerable amount of work has been done on the overall economic consequences of higher oil prices, little has been done on the effects of higher natural gas prices. However, until recently, oil and natural gas prices were fairly strongly linked and so research on the impacts of higher oil prices can be used as a proxy for studying the effects of higher natural gas prices. Stephen Brown, director of energy economics at the Federal Reserve Bank of Dallas made a rough estimate using information from oil price shock research and stated that a sustained doubling of (wellhead) natural gas prices would reduce U.S. Gross Domestic Product by 0.6 to 2.1 percent and increase inflation by a similar amount. He noted that the economic effects would vary widely across regions and industries: States that produce and export natural gas, such as Wyoming, would gain, while states that import natural gas, such as Washington on average would experience economic loses due to higher gas prices.

Natural Gas Price Forecasts

Near-Term Forecast

During the summer of 2003, gas storage injections continued at a record pace; the 10-week period from June 1 saw nearly 1 Tcf of gas injected into storage compared to a 10-year average for this period of 763 Bcf. By early November 2003 gas storage was at 3,187 Bcf, well above what is considered the safe level for a normal winter heating season. As a consequence of the greater than normal additions to gas storage, spot market prices have declined significantly. June monthly spot market prices that averaged \$6/MMBtu, gave way to a November 2003 average of just over \$4/MMBtu. Prices in the natural gas futures market also declined appreciably over the summer as gas storage inventories grew, but show signs of remaining high through 2004: New York Mercantile Exchange (NYMEX) futures contracts are shown in Figure 6.3 below. During early 2004, as oil prices have risen, gas futures prices have moved back above \$5/MMBtu. The EIA reports that natural gas prices averaged \$5.51/MMBtu for 2003, and forecasts that they will remain at around \$5/MMBtu in 2004 and 2005 (EIA, 2004). A cold winter or extremely hot summer could cause demand to increase and prices to climb again.

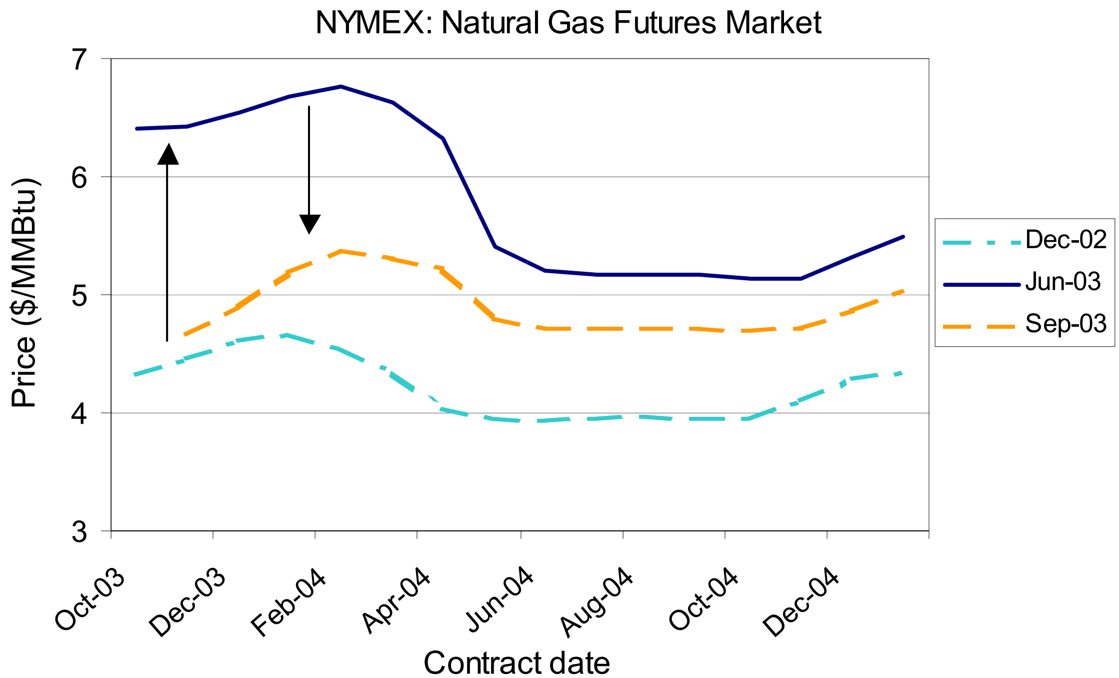

Figure 6.3: Natural Gas Futures Market
Source: The Wall Street Journal

Long-Term Natural Gas Price Forecasts

The Northwest Power and Conservation Council (NPCC) in 2003 released its *Draft Fuel Price Forecasts for the Fifth Power Plan*. The draft report includes a review of historical Northwest natural gas consumption and prices, as well as a forecast of future natural gas consumption and prices through 2025. The report observed that regional consumption had grown rapidly over the last decade or more, with an average annual growth rate of 6.8 percent during the period from 1986 to 2000. Growth was particularly rapid in the industrial and electrical generation sectors. This growth coincided with a period of low or falling natural gas prices. Historically in the Northwest, natural gas powered electrical generation had a low capacity utilization factor, only being used for peaking plant operation, or full time only on an emergency basis when hydroelectric generation was insufficient due to low rainfall or snowpack. This pattern began to change in the late 1990s as gas-fired generation that was intended to operate at a high capacity factor was either proposed or put into service. Since 2000, 3480 MW of gas-fired electrical generating capacity has been installed in the Northwest, 1390 MW of this in Washington. An additional 8,100 MW is planned, permitted or under construction for the region, and 2,120 MW for Washington State[65].

The bulk of the new gas-fired electricity generation is expected to require firm natural gas supplies and pipeline service. Because of its low capacity utilization factor, earlier gas-fired generation typically used interruptible supply and pipeline service, which aided in

[65] Much of the 7,900 planned or permitted gas-fired generation projects in the region have been suspended and are not likely to be developed.

meeting peak day demand requirements for the region. In addition, the new gas-fired generation units will be running at maximum capacity during the winter months when demand in the commercial and residential sectors is highest, thereby putting added strain on the gas transportation infrastructure. As the gas usage pattern for electricity changes, other strategies, such as increased pipeline capacity, gas storage and LNG peak shaving facilities will become necessary.

The NPCC predicts that supplies from the WSCB in Canada and the Rockies region will be sufficient over the next 20 or so years. The NPCC used its own forecasting model and developed low to high range price forecasts for natural gas out to 2025. These results are summarized in Table 6.1 below.

Table 6.1: NPCC forecast of U.S. wellhead natural gas prices (2000 $/MMBtu)

Year	Low	Medium	High
2000	3.60	3.60	3.60
2003	4.00	5.00	5.80
2005	2.50	3.25	4.25
2010	2.40	3.25	3.70
2015	2.55	3.40	3.70
2020	2.60	3.50	4.00
2025	2.65	3.60	4.25
Demand growth rate	*0.29*	*0.51*	*0.00*

The NPCC noted that because of the diminished amount of excess productive capacity in the natural gas industry, price volatility should be expected, and that price excursion above and below the forecast price trends shown above should be expected. Factors influencing price volatility included, but are not limited to, unseasonable weather, and high or low levels of economic growth.

The NPCC regional price forecasts are compared with the national prices forecast by the National Petroleum Council (NPC), the Energy Information Administration (EIA), and the California Energy Council (CEC) in Table 6.2 below.

Table 6.2: Summary of price forecasts ($/MMBtu)

Forecast year	**NPCC (2003)**	**NPC 1999 & 2003**	**EIA 2001 & 2004**	**CEC (2003)**
Base year price (yr)	3.60 (2000)	2.00 (1998) 5.00	3.60 (2000) 2.95 (2002)	2.95 (2002)
2005	3.25	2.50 4.50	2.66 ---	3.15
2010	3.25	3.00 4.25	2.85 3.40	3.40
2015	3.40	3.50 4.25	3.07 4.19	3.79
2020	3.50	---	3.26 4.28	---

The more recent price forecasts are for the most part reasonable, and indicate that the average natural gas wellhead price will be approximately $4/MMBtu (expressed in 2000 dollars) by 2015. Over the next couple of years gas prices may be slightly higher than the forecast 2005 values shown above. By the 2010 to 2015 time period significant quantities of LNG and Arctic gas should be entering the market, which will dampen upward price pressure and volatility.[66]

Summary

Since 2000, natural gas prices have been significantly higher and more volatile than they were during the 1990s. The key factors leading to high and volatile prices, mitigating factors, and the short-term and long-term prices forecasts are summarized below.

1. Recent high prices and volatility are primarily caused by gas supply limitations. The move to short-term contracts and the spot market tend to exacerbate price volatility.
2. Prior to 1997 there was sufficient excess gas production capacity to limit price increases and volatility. By 2000 a supply-limited market had developed and remains with us today.
3. Price and volatility are affected by weather, storage levels, storage withdrawal rates, oil prices, inelasticity of supply and demand, pipeline constraints, and the lack of timely and reliable information.
4. Factors that can mitigate high prices and volatility are sufficient storage, fuel switching capability, excess productive capacity, long-term contracts, and more timely and reliable information.
5. Higher gas prices have resulted in demand destruction and fuel switching primarily in the industrial sector, as well as short-term conservation and efficiency efforts.
6. The Industrial Energy Consumers of America estimate the direct cost of recent high gas prices at $111 billion over 41 months. The inclusion of indirect costs would add significantly to this cost number.
7. The EIA forecasts continued high but easing natural gas prices during 2004 and 2005. However, the futures markets forecast prices in the range of $5 to $6/MMBtu for the next two years.
8. The EIA and the NPC forecast prices in the low $4/MMBtu range (2000 dollars) for the year 2015. When significant new gas resources, such as LNG imports and Arctic gas, are developed upward price pressure and price volatility will be moderated.

The higher natural gas prices that are anticipated for the near- to mid-term will have a pronounced impact on gas demand growth through 2010. High gas prices will make the payback for efficiency and conservation efforts by residential, commercial and industrial consumers appear even more attractive. The industrial sector will continue to experience demand destruction as energy intensive businesses relocate to parts of the world with less expensive energy resources. In the electrical generation sector, high gas prices will stimulate interest in efficiency programs, and coal-fired and renewable electricity generation.

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[66] The NPC and the EIA evaluated a scenario where development of LNG imports and Arctic gas were limited for political and financial reasons. The resulting long-term market price for natural gas in this scenario was substantially higher.

Section 7: Natural Gas Pipeline and Storage Capacity

Introduction

The capacity of pipelines to deliver natural gas combined with the production of natural gas are two necessary components that ensure adequate supply. This section of the report describes pipeline infrastructure, capacity, storage, and expansion activities. The discussion begins with an overview of the natural gas purchasing and delivery process and the pipeline expansion and permitting processes in the United States and Canada. This is followed by an overview of the pipeline systems in Western North America and the increasing interconnectedness of the Western systems with the systems across North America. The end of the section describes individually and in greater detail the three major pipelines that affect the Pacific Northwest, including system overviews, operations, Canadian/domestic supply splits, contracted capacity, constraint points, expansion activity (recent and planned), and changes in storage.

There are three major pipelines that serve Washington State. They are the Northwest Pipeline Corporation, a subsidiary of Williams (Northwest), National Energy & Gas Transmission Gas Transmission Northwest Corporation (GTN)[67] and Duke Energy Gas Transmission (DEGT).[68] DEGT delivers gas from the gas fields in northern British Columbia and Alberta to the Washington border at Sumas. From Sumas, the gas is delivered to the Northwest pipeline system, which continues southeast to the Rocky Mountain gas fields. DEGT receives gas from Canada at the U.S. border in Kingsgate, Idaho, and then almost immediately crosses into Washington. (See Figure 7.1 for an overview map.)

The Pacific Northwest once was the near-exclusive recipient of large and otherwise isolated gas supplies in British Columbia. Over the past few years, major interconnections have been built between pipelines in the West and eastbound pipeline systems. The Alliance Pipeline, which came into operation in 2000, delivers gas from B.C. and Alberta to Chicago. The Kern River Pipeline and the Trailblazer Pipeline have provided new eastern and southern outlets for gas in the Rockies (see Figure 7.2). It can now be said that the Pacific Northwest, and in fact North America, is fully integrated into a North American pipeline system, and as a result, a North American market.

Natural Gas Purchasing and Delivery Process

Shippers, including local distribution companies, large industrial customers, and energy marketers, purchase capacity on the pipelines to deliver gas from particular suppliers and receipt points on the system to particular delivery points. Shippers can elect to purchase firm transportation, which will be available under all but emergency circumstances, or non-firm transportation, which will not be available when firm transportation usage is high. For more detailed information on this process, see Section 3 of the previous version of this study, *Convergence: Natural Gas and Electricity in Washington*, Washington State Office of Trade and Economic Development, May, 2001.

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[67] National Energy & Gas Transmission Gas Transmission Northwest (GTN) was formerly called PG&E Gas Transmission Northwest.

[68] Duke Energy Gas Transmission West (DEGT) was formerly called West Coast Pipeline

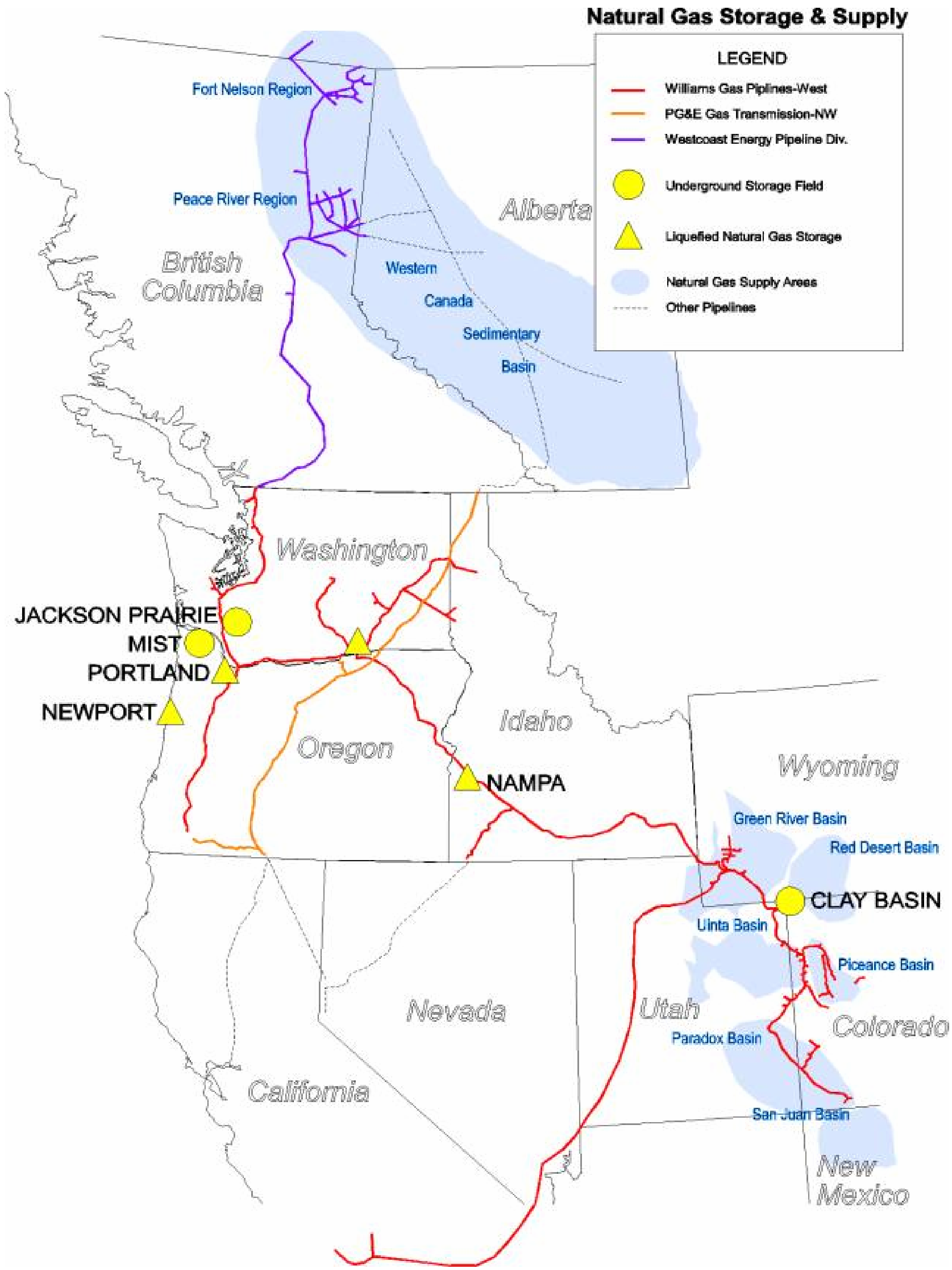


Figure 7.1: Northwest Natural Gas Storage and Supply Map

Note: Since this map was created, the name of PG&E Pipeline has changed to National Energy & Gas Transmission Gas Transmission Northwest (GTN) and Westcoast Pipeline has changed its name to Duke Energy Gas Transmission West (DEGT).

Pipeline Expansion Process

The need for additional pipeline capacity to meet demand growth can be met in several ways: Build a new pipeline, convert an oil pipeline; or expand an existing natural gas pipeline system. Building a new pipeline is much more expensive than the other two methods. The costs of new capacity can be allocated on either a *rolled in* or an *incremental* basis, as determined by the Federal Energy Regulatory Commission (FERC). If the cost of expansion is relatively minor, adding both the new costs and the new throughput to the existing rate base may result in rates that are lower than before the expansion. In this case, costs of the expansion are rolled into existing rates. If substantial new investment is required such that rolling in the expansion costs would result in rate increases for existing shippers, the costs may be assigned on an incremental basis. That is, the new shippers pay the costs of the new capacity, while existing shippers continue to pay the same rate.

Permitting process in the United States and Washington State

Typically, in addition to acquiring FERC approval for an expansion project, the environmental and construction permitting process involves working with many federal, state and local agencies. The federal agencies include the U.S. Forest Service, U.S. Department of the Interior's Bureau of Land Management, U.S. Corps of Engineers, U.S. Fish & Wildlife Service and the National Marine Fisheries Service. State agencies in Washington include the Washington State Department of Community, Trade and Economic Development Energy Facility Site Evaluation Council (EFSEC), the Office of Archaeology and Historic Preservation, and the state departments of Ecology, Natural Resources, and Fish & Wildlife. Any impacted local jurisdictions such as counties and cities may also be involved.

Depending upon the scope of the project and the issues involved, the complete permitting process for an expansion project typically takes one to two years. Likewise, the total cost of the permit process for an expansion project is dependent upon the project scope and issues. For major projects, the cost of preparing and pursuing all the required permit applications typically would be a few million dollars.

Natural gas facilities subject to EFSEC review include:

- Natural gas, synthetic fuel, gas, or liquefied petroleum gas pipelines larger than 14 inches in diameter and greater than 15 miles in length (intrastate only);
- Liquid natural gas facilities with capacity to receive an equivalent of more than 100 MMcf/day that has been transported over marine waters;
- Any underground natural gas storage reservoir capable of delivering more than 100 MMcf/day.

In Washington State very few pipelines fall under the jurisdiction of EFSEC because nearly all pipelines are inter-state, which is FERC's jurisdiction. In recent years, applications for the Cross-Cascades pipeline (withdrawn in 1995) and the Sumas 2 Energy Facility (permitted in 2003) came to EFSEC.

Permitting process in Canada

Duke Energy Gas Transmission (DEGT) is regulated by the National Energy Board (NEB) of Canada and must apply to this board for expansions of its pipeline facilities. DEGT also works with the Canadian Department of Fisheries and Oceans, and Environment Canada, both of which are federal agencies, as well as many provincial and local agencies.

When seeking approval to expand its facilities, DEGT files a facilities application with the NEB, which then assesses the need and justification for the new facilities, including available supply and market demand, the proposed project design and construction plans, the impacts on the environment, landowners, the public and aboriginal groups, and the financial impacts associated with financing the expansion. The size of the project will determine whether a public hearing is required.

There is no charge for the project application, apart from the time of the staff devoted to the regulatory process. The length of time it takes to gain regulatory approval for a project varies according to many factors including the complexity of the project and the number of interveners and stakeholders. In general, a mainline expansion is the most complex application and it takes approximately 30 months from the close of the open season to the in-service date. Smaller projects require a commensurate amount of time.

For further discussion of the permitting process in the United States and the Federal Energy Regulatory Commission's role, see Section 3 of *Convergence: Natural Gas and Electricity in Washington* (OTED, 2001).

Western North America Pipeline System Overview

International and Inter-Regional Pipeline Capacity and Expansion

Both Northwest Pipeline and GTN, the two pipelines that serve Washington, are connected to major gas transmission lines in Canada. Northwest Pipeline receives gas supplies from DEGT and GTN, and GTN receives supplies from TransCanada Pipeline. Both DEGT and TransCanada are connected to gas gathering systems in the producing regions of British Columbia and Alberta. Both of these pipelines are also connected to systems that serve all of Canada and much of the northern half of the United States, as shown in Figures 7.1 and 7.2. The map in Figure 7.3 shows the relative capacities of these pipelines from a national perspective.

Table 7.1: Origin of Gas Serving the Northwest

Pipeline	Canadian Gas	Domestic Gas
Northwest Pipeline	66%	33%
GTN	92%	8%

The Alliance Pipeline, built in 2000, delivers 7.2 bcf/day from Northern British Columbia to the Chicago area, serving Canada and the Midwest along the way. It has been operating near capacity since it first came on line. The TransCanada pipeline spans nearly the entire width of Canada from the Alberta/Saskatchewan border east to Quebec/Vermont. In 2002, deliveries to export border points comprised approximately 53 percent of total deliveries. These two Canadian systems have ready access to Midwestern and Eastern markets, as well as the Pacific Northwest.

Northwest Pipeline is also connected to the major supply regions in the Rocky Mountains and relies on this region for approximately one-third of it supply, as shown in the inset table above. In Figure 7.2 below, it is apparent that recent additions in the Kern River system and the Trailblazer system compete directly for supplies with Northwest Pipeline. These two pipelines provide major new connections to markets in California and on the East Coast. The 900 MMcf/day Kern River Transmission system expansion came on line in May, 2003, to transport natural gas from Wyoming to California and Nevada. Kern River's market is comprised to a large extent of power generators serving summer cooling needs in California.

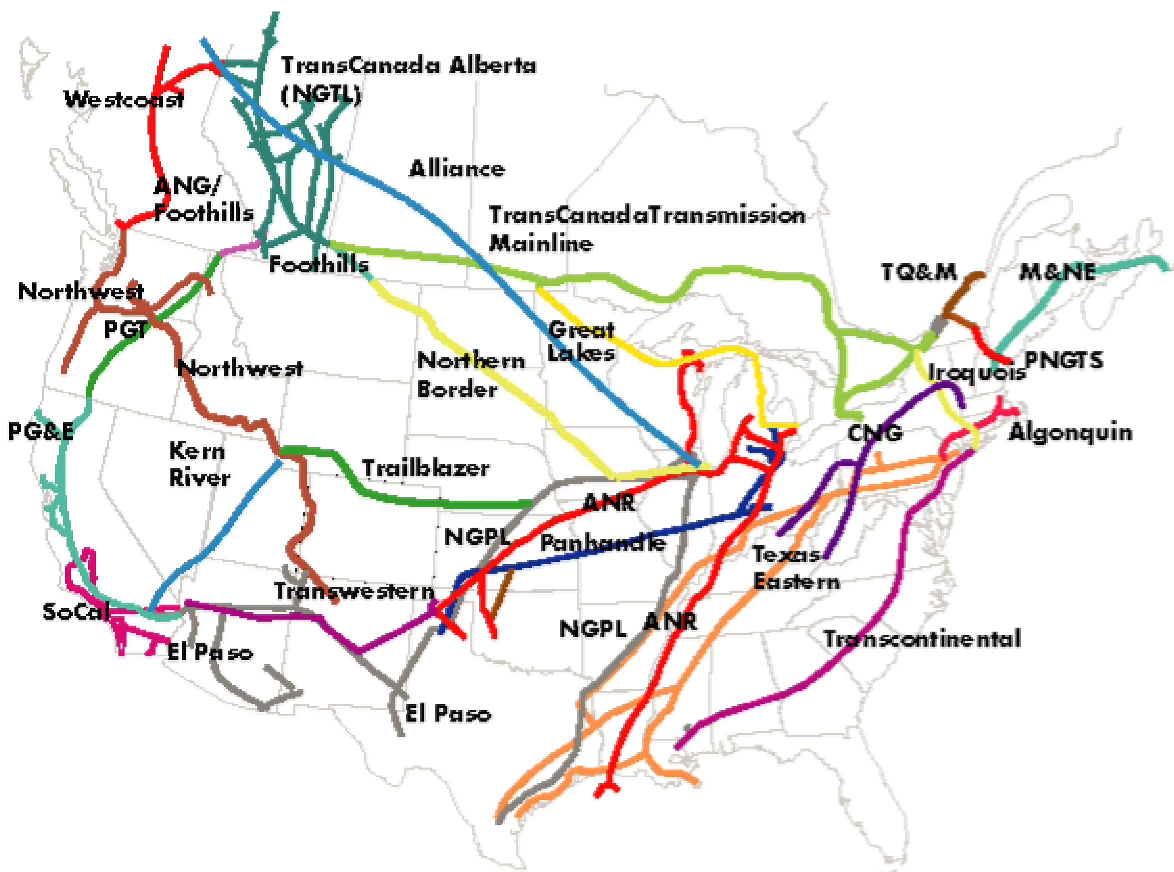


Figure 7.2 Major North American Pipelines

Source: National Energy Board of Canada - website: http://www.neb.gc.ca/energy/images/gasmap_e.gif

Note: Since this map was created the name of PG&E Pipeline has changed to National Energy & Gas Transmission Gas Transmission Northwest (GTN).

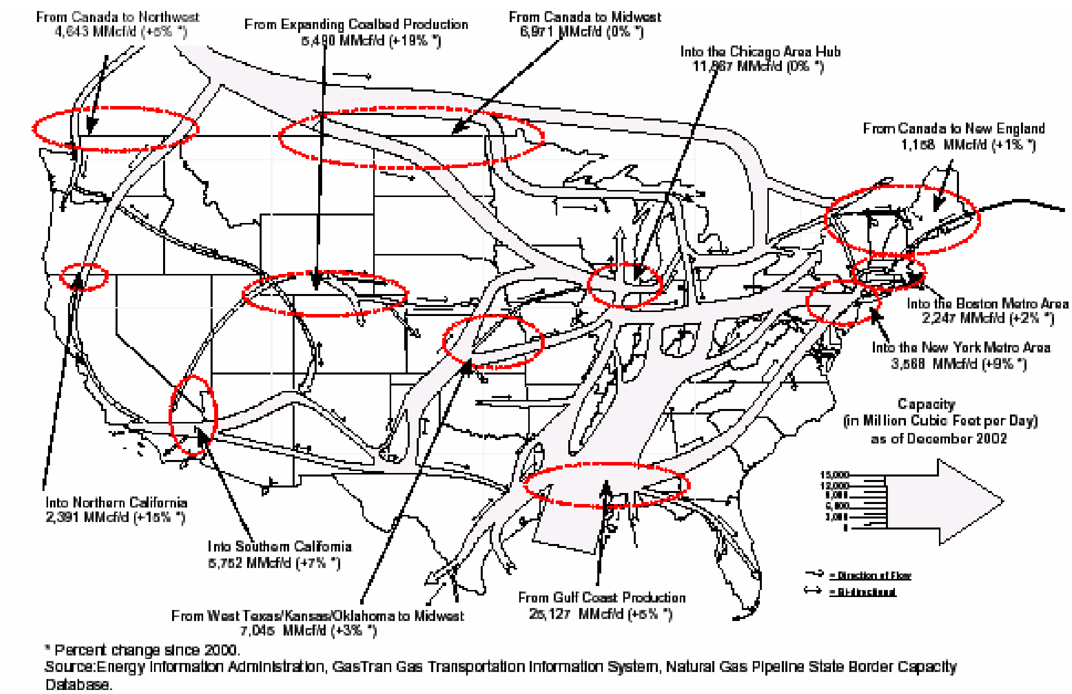
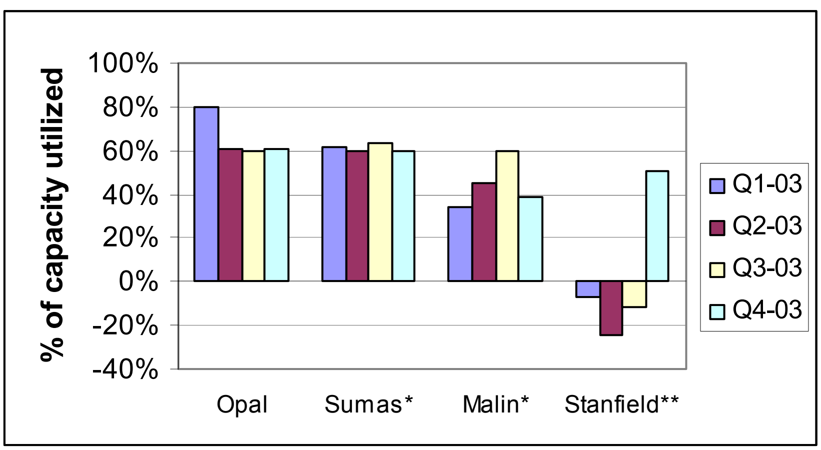


Figure 7.3 Major Natural Gas Transportation Routes and Capacity Levels at Selected Locations, U.S.
Source: Energy Information Administration
http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2003/Pipenet03/ngpipenet03.pdf

Table 7.2 below shows pipeline capacity utilization rates throughout 2003. The Kern River Expansion Project, discussed later in this section, went into effect in May of 2003 and increased flows through Stanfield, Oregon.

Table 7.2 Pipeline Utilization Rates



Source: Natural Gas Week and Bentek Energy
* Net flow
** Capacity delivering to NW is 630 MMcf/d; receiving from NW is 200 MMcf/d. A negative utilization rate connotes that the flow is toward PGT and the utilization rate calculation is based on the receipt delivery into PGT.

Development of a Continental Market for Natural Gas

Along with the increased ability of gas to flow both east and west comes increased risks and benefits to the Northwest. In recent years, the Northwest has sustained lower gas prices than eastern markets. Integration of the Canadian and Rocky Mountain supply basins with the North American market has resulted in the emergence of a "North American" price in all regions rather than a "regional" price in areas such as the Rockies, Western Canadian Sedimentary Basin (WCSB) and end use markets of the Pacific Northwest. Prices still vary but the difference between gas trading hubs is much smaller than in the past. (See Section 6 for discussion of prices.)

The Northwest and GTN pipelines are transporters of gas (they don't actually own all of the gas that they carry) and are affected by price insofar as the price affects pipeline flows. For example, GTN pipeline flows will be influenced by the price difference between AECO (a major gas trading hub in Alberta, connected to the TransCanada Pipeline) and Malin, Oregon, where it connects with Northwest Pipeline. On Northwest, price differences between Canadian and domestic gas will impact displacement.[69] Displacement is the ability of a bi-directional pipeline such as Northwest to deliver Canadian gas to the southern end of the pipeline and Rocky Mountain gas to the northern end of the pipeline by essentially offsetting the two – physically, the contracted gas couldn't flow in opposite directions over the same pipe. Price signals are considered leading indicators of the location and timing of needed incremental pipeline infrastructure enhancements. However, other signals, such as high load factor—an indicator of usage—and increased prices in other industries, such as spark spread in the power generation industry, will also spur expansion.

Pipeline Expansions into Producing Fields

Alaska

As of January 1, 2000, the Alaska Department of Natural Resources estimated the state's remaining recoverable natural gas reserves at 33.5 trillion cubic feet of gas. Production from natural gas fields in the Cook Inlet Basin currently totals more than 200 Bcf/yr. This production serves local energy needs and has been exported as liquefied natural gas (LNG) to Tokyo Electric on long-term contract since 1969.

Currently, pipelines—or pipelines in combination with LNG plants—are the options under consideration by the major producers and pipeline companies for bringing North Slope gas to market. There are three possible routes to move North Slope gas to market. They are the Alcan Highway Route, the Over-the-Top Route and the All-Alaska route. See Figure 7.4. Also under consideration is the possibility of additional LNG facilities. The state, in cooperation with energy companies, has studied the subject of pipeline development periodically over the last 25 years. The most recent study was conducted in 2002 and focuses on the options for state contributions for funding the various options.[70]

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[69]See Section 3 of the earlier version of this report, *Convergence: Natural Gas and Electricity in Washington* (Washington State OTED, May, 2001) for in-depth information about displacement.

[70]*State Financial Participation in an Alaska Natural Gas Pipeline* http://www.arcticgaspipeline.com/Reference/Documents&Presentations/A-legislature/Final%20report2.pdf

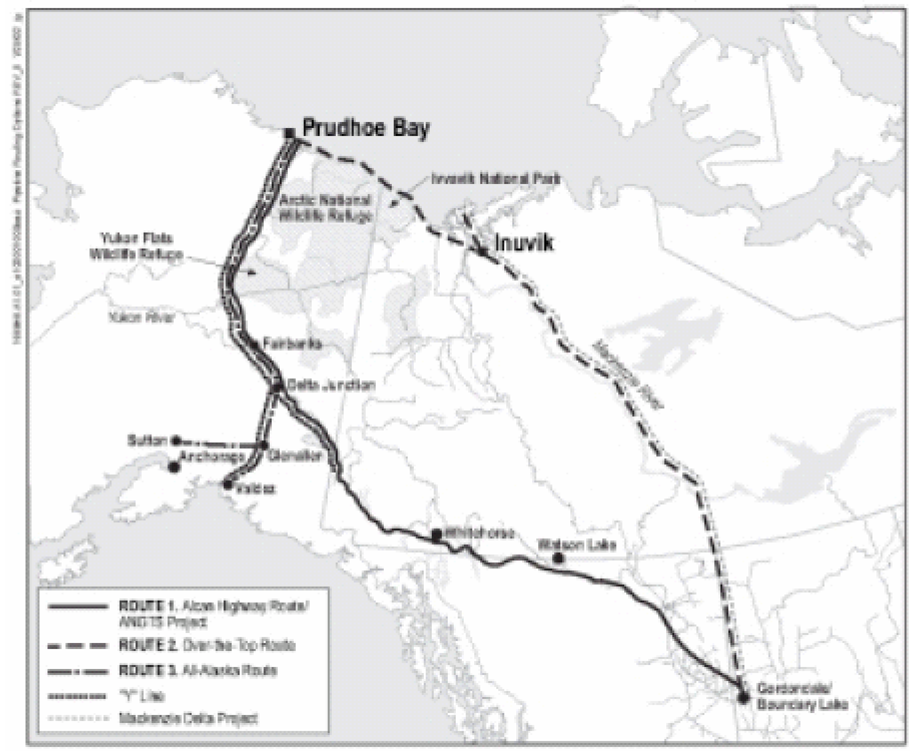

Figure 3-1
Proposed Pipeline Routes

Figure 7.4 Proposed Alaskan Pipeline Routes

Below is an excerpt from the most recent study, conducted by the state of Alaska in 2002, which looked at the feasibility of state assistance in financing Alaska pipeline development.

> *To construct a multi-jurisdictional pipeline and get it financed in a timely manner requires regulatory approvals, a known and agreed-upon tariff structure, an approved pipeline route and set of initial rates, and transportation agreements that have a term and volume to allow financing and that mirror each other by jurisdiction and in receipt and delivery point. Each section of an integrated, multi-jurisdictional pipeline needs to have understood contract terms that match adjoining upstream and downstream facilities. This includes transportation volumes (size of pipe), gas quality standards (type of gas), known tariff structure (the cost to move the gas from Point A to Point B), and simultaneous service. Each piece of the pipe must be operational concurrently, must physically be capable of moving the volumes nominated by its shippers or upstream pipeline, and be able to deliver like volumes into downstream pipelines or to downstream customers. The contract volumes, terms, and titles need to match. As noted above, under ANGTA [*Alaska Natural Gas Transportation Act] *these issues were largely*

> *negotiated as part of the supply arrangements assumed by the pipelines. In today's world, this might not work.*
> *…The manner by which firm capacity would be obtained for the Alaska pipeline and its alignment with existing downstream pipeline firm capacity is unclear. This might be the most significant issue surrounding the economic and commercial viability of building these pipeline facilities.*

The state of Alaska is granted federal price support in the current version of the National Energy Bill (2003) to assist the development of any of these pipelines. At the time of this writing (early 2004) the bill has not been approved.

Northwest Pipeline System

The majority of information contained in this section on the Northwest Pipeline originated from the pipeline company itself via a survey conducted by the Community Trade and Economic Development Energy Policy Division and its contractors. The company was asked to provide information about the impact of new pipelines on its business, the ratio of gas from Canada versus the Rocky Mountains, major receipt points, largest shippers, capacity utilization, constraints, expansion plans, permitting process, storage and long-term plans.

System Overview

The Northwest Pipeline Corporation, a subsidiary of Williams, owns and operates a transmission system extending from points of interconnection with El Paso Natural Gas Company and Transwestern Pipeline Company near Blanco, New Mexico, through the states of New Mexico, Colorado, Utah, Wyoming, Idaho, Oregon and Washington, to the Canadian border near Sumas, Washington, where it interconnects with the facilities of both DEGT and Terasen Sumas, Inc.

Northwest Pipeline is a one-third owner of the Jackson Prairie Storage Project in Lewis County, Washington, and also owns and operates the Plymouth LNG facility in Benton County, Washington, both used by Northwest Pipeline to provide contract storage services. To assist in balancing its transportation services, Northwest Pipeline also has contracted for underground natural gas storage capacity from Questar Pipeline Company in the Clay Basin Field in Daggett County, Utah.

System Operations

Northwest Pipeline is a bi-directional pipeline that relies on a combination of physical and displacement capacity to meet firm contract commitments. This allows for maximum utilization of pipeline capacity, achieving natural gas flows into and out of the pipeline system that are much higher than one-way physical capacity would allow. Because Northwest Pipeline has delivery and receipt points in a number of locations throughout the western states, customers in the southern portion of the system can contract for delivery of Canadian gas and those in the North can contract for gas from the Rocky Mountains or the San Juan Basin in New Mexico. Contracted gas flowing in opposite directions over the same pipeline segment partially offset each other, thus all the gas from Canada does not necessarily have to flow to the southern part of the system and vice versa. This phenomenon is called *displacement*.

Canadian/domestic gas supply split

Canadian gas enters the Northwest system at Sumas from the DEGT Pipeline and at Starr Road, Palouse and Stanfield from the GTN Pipeline. Customers in the Pacific Northwest have contracted for approximately one-third of domestic supply and two-thirds of Canadian supply.

On Northwest's system, the percentage of supplies from Canadian and domestic sources is significantly influenced by pricing differentials between the basins. The actual (as opposed to contractual) Canadian/domestic split changes as price changes. For example, during the winter of 2002-03 domestic gas was far cheaper than Canadian gas, and the Kemmerer corridor (western border of Wyoming, near Idaho) was flowing consistently over physical capacity. However, Northwest was able to use its balancing flexibility at Jackson Prairie to mitigate customer impacts. Another effect of low domestic prices is that Northwest delivered large volumes of gas to Stanfield. Much of the time Stanfield delivers Canadian gas to Northwest.

Figure 7.5 illustrates the changing Canadian/domestic actual supply split for the past few years. Note that the data for 2003 does not yet reflect the full impact on price of the Kern River Expansion. (The graph excludes storage.)

On May 1, 2003, the Kern River Expansion went into service. Gas that had been trapped behind bottlenecks in the Rockies now has access to markets in California. Domestic gas prices rose almost immediately to meet, and ultimately exceed, the Sumas gas price. Naturally, as prices rose, flows through the Kemmerer, Wyoming, corridor plummeted. However, as fall progressed into winter, the gas prices of Canadian and domestic supplies roughly converged and domestic and Canadian supplies became more balanced. Since May 2003, both Canadian and Rockies prices have traded at a discount to the NYMEX price, but both have tracked NYMEX volatility.

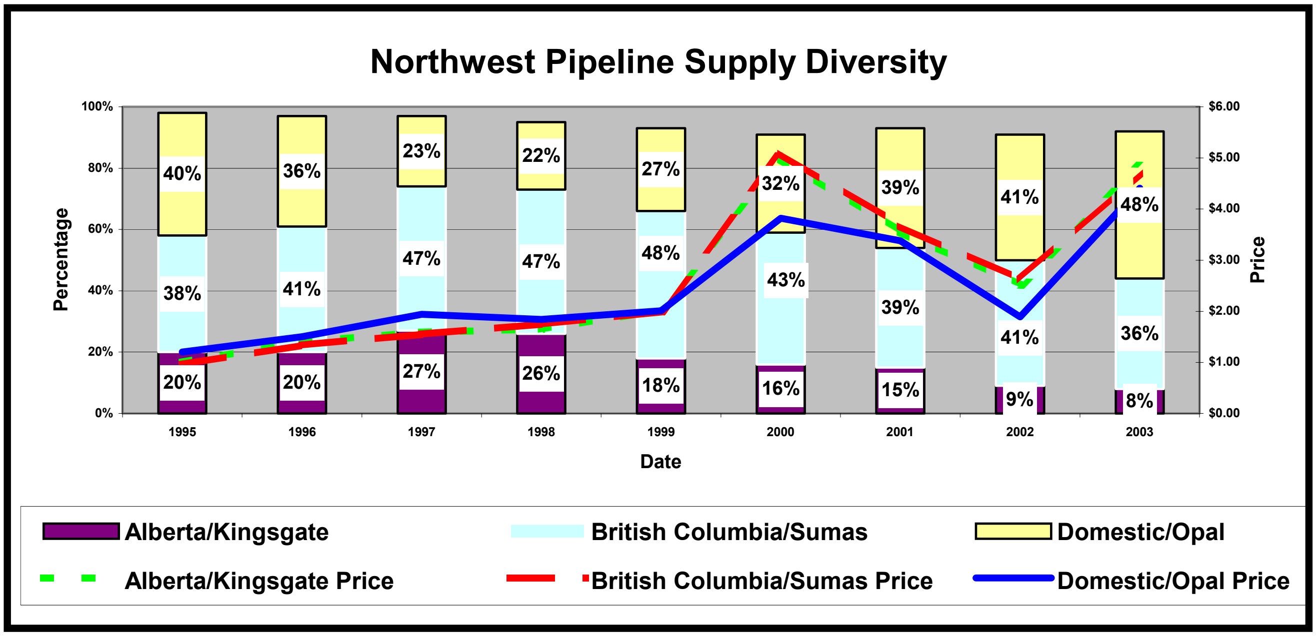

Figure 7.5: Northwest Pipeline Supply and Average Price Source: NW Pipeline

Shippers, Contracts and Delivery Points

Table 7.3 below shows the major receipt points along Northwest Pipeline's system.

Table 7.3 Contracted Capacity at Major Receipt Points

Location	Receipt Point Firm Capacity (MDth/day)
Sumas *	1,314
Starr Road**	165
Stanfield**	638
Palouse	20
Kemmerer**	721
Total w/o Storage	2858
Jackson Prairie***	1000
Plymouth LNG	300
Total Storage	1,300

* Capacity after the Evergreen Expansion went into service in October 2003.
**Kemmerer can be a mainline constraint between domestic receipt points and the Pacific Northwest. This number reflects contracted capacity. Physical capacity after the Rockies Expansion increased to 653 thousand decatherms/day.[71] Northwest's system is dependent upon approximately 75 MDth/day of displacement flow. If the entire northbound contractual capacity of 721 MDth/day were to get scheduled without any gas

[71] Thousand decatherms (MDth). A decatherm is equal to a million British Thermal Units (Btu).

flowing south (i.e. displacement gas), then Northwest would have to call a general operational flow order (OFO).
***Capacity includes a maximum of 880 MDth firm 120 MDth best efforts

Table 7.4 below shows the top reported shippers on Northwest's system based on contracted demand.

Table 7.4 Top Ten Shippers on Northwest Pipeline (Contracted)

Companies*	TF-1 Maximum Daily Quantity (MDth/day)
Puget Sound Energy, Inc.	456
Northwest Natural Gas Company	352
Pan-Alberta Gas (U.S.) Inc.	243
Cascade Natural Gas Corporation	208
Avista Corporation	200
Duke Energy Trading And Marketing L.L.C.	188
Intermountain Gas Company	120
Chehalis Power Generating Limited Partnership	90
Sierra Pacific Power Company	69
Southwest Gas Corporation	68

*Includes long-term firm base contract shippers

Subscribed Capacity and Load Capacity Factor

Each day, shippers with contracted capacity nominate the volume of gas they will need. Generally, the daily nominations are less than contracted capacity. The average ratio of nominated flows to total base contract receipt capacity for markets in the Pacific Northwest is approximately 66 percent. The load factor on different segments of the system can vary due to pricing dynamics, constraints on the system, and shipper nominations for specific points of receipt and delivery.

Major Physical Constraint Points

Northwest relies significantly on displacement to meet its contract obligations to transport Canadian and domestic gas on its bi-directional system. If transportation nominations are excessively skewed in reliance upon any one major supply source for any reason (for example, price disparities between Canadian and domestic supplies), constraints can occur. The major potential constraint points on Northwest's system are south through the Chehalis, Washington, corridor and north through the Roosevelt, Washington, and Kemmerer, Wyoming, corridors. As discussed below, Northwest has recently completed projects to reduce reliance on displacement through both of these constraint points.

Expansion into New Production Areas

Northwest has been working with numerous producers and other pipelines to provide additional access to growing Rockies supplies.

Changes in Storage Capability

The Jackson Prairie Project in Lewis County, Washington, is operated by Puget Sound Energy on behalf of the three joint owners, Northwest, Puget and Avista. In August 2002, the project operator received FERC approval to implement a phased water withdrawal/gas injection storage capacity expansion project. The authorized expansion totals 10.5 Bcf over the 2002-2008 period (6.3 Bcf working gas plus 4.2 Bcf cushion gas). Only Avista participated in the 2002 expansion phase of approximately 1.4 Bcf (60 percent working and 40 percent cushion). The 2003 through 2007 expansion phases are anticipated to be approximately 1.75 Bcf each (1.05 Bcf working plus 0.7 Bcf cushion). The 2008 phase then will complete the authorized expansion levels. Northwest's one-third share of the 2003 expansion phase storage capacity was approximately 0.475 Bcf (0.285 Bcf working gas plus 0.190 Bcf cushion gas). By the completion of the expansion project in 2008, it is anticipated that Northwest's share of the storage expansion capacity will total approximately 3.5 Bcf (2.1 Bcf working plus 1.4 Bcf cushion).

Recent Capacity Changes

In the Fall of 2003, Northwest completed two projects to reduce displacement. The Rockies Expansion Project included installation of approximately 91 miles of new pipeline loops and approximately 26,000 net horsepower of compression facilities at various locations in northwestern Wyoming and southeastern Idaho. This project increased Northwest's physical north flow capacity in the Kemmerer Corridor by approximately 175 MDth/day, to replace displacement capacity currently relied upon to serve existing north flow transportation service obligations in the Kemmerer, Wyoming, to Stanfield, Oregon, corridor. The Rockies Project was designed primarily to replace a contract-specific obligation that terminated October 31, 2003, to flow 144 MDth/day south to provide displacement in this corridor. The cost of this project was $140 million.

The Columbia Gorge Corridor facilities increased Northwest's physical north flow capacity in that corridor sufficient to replace approximately 54 MDth/day of displacement capacity currently relied upon to serve existing north flow transportation service obligations. The total estimated cost of this project is approximately $241 million, $198 million for the Sumas-Chehalis Corridor facilities and $43 million for the Columbia Gorge Corridor facilities. Northwest’s customers agreed to roll in the costs of both the Rockies and Columbia Gorge projects because they provide a general system benefit.

Northwest also completed an incremental project in October of 2003. The Evergreen Expansion Project included installation of approximately 28 miles of new pipeline loops and approximately 64,000 net horsepower of compression facilities in the Sumas-Chehalis Corridor in Washington State and installation of approximately 24,000 net horsepower of compression facilities in the Columbia Gorge Corridor in Washington. The Sumas-Chehalis Corridor facilities increases Northwest's physical south flow capacity in that corridor by approximately 2201 MDth/day to help provide 277 MDth/day of new long-term firm incremental transportation service for power generation loads.

Other Expansion Plans

Northwest has proposed to build the 9-mile, 16” MDth/day Everett-Delta Lateral to connect its system with that of Puget Sound Energy to serve business and population growth in Snohomish County. The lateral will have a capacity of 113 MDth/day and is expected to be in service on November 1, 2004. Williams is also a partner with BC Hydro on the GSX Project to serve power generation loads on Vancouver Island, B.C., as well as potential markets on the U.S. mainland.

National Energy & Gas Transmission Gas Transmission Northwest (GTN)

The majority of information contained in this section on the National Energy & Gas Transmission Gas Transmission Northwest (GTN) pipeline originated from the pipeline company itself via a survey conducted by the OTED Energy Policy Division and its contractors. The company was asked to provide information about the impact of new pipelines on their business, the ratio of gas from Canada versus the Rocky Mountains, major receipt points, largest shippers, capacity utilization, constraints, expansion plans, permitting process, storage and long-term plans.

System Overview

The GTN Pipeline interconnects with the TransCanada Pipeline at Kingsgate, B.C. Gas produced in Alberta is delivered to the Western United States via interconnections with the Northwest Pipeline at Spokane and Palouse, Washington, and Stanfield, Oregon; and Pacific Gas and Electric Company and Tuscarora Gas Transmission Company at Malin, Oregon. GTN also connects with Avista Utilities and Cascade Natural Gas.

GTN is a dual pipeline system consisting of approximately 612 miles of 36-inch diameter gas transmission line and approximately 612 miles of 42-inch-diameter pipe. The system also includes smaller diameter laterals to Coyote Springs and Medford. GTN can transport about 2.9 Bcf/day, or 2,900 MDth/day. More than 1,800 MDth/day can be delivered to California and Nevada and up to 1,000 MDth/day to the Pacific Northwest. In 2003, typical deliveries to the Pacific Northwest from the GTN system averaged 554 MDth/day in the winter and 385 MDth/day in the summer. In 2003, the peak day delivery to the Pacific Northwest from GTN was 954 MDth.

Pipeline Operation and Natural Gas Flows

Natural gas flow on the GTN system is essentially one-way from Canada to California. Gas can be delivered at various points along the system including three interconnection points with Northwest Pipeline and direct connects to local distribution companies such as Avista and Cascade Natural Gas. GTN also delivers to generators at Coyote Springs, Klamath Falls, Hermiston, Oregon; and Rathdrum, Idaho. Natural gas is received primarily from TransCanada Pipeline at Kingsgate, B.C., but GTN can receive a small amount of gas from the Northwest Pipeline at Stanfield. Even though there is not physical capacity to receive gas at other locations, it is possible to have nominations for receipt at other points by using displacement at other points on the system.

Canadian/domestic split gas supplies

GTN's system is a unidirectional pipeline that was built for and relies almost entirely upon Canadian gas. GTN's current contracts are 89 percent Canadian (receipts at Kingsgate) versus 11 percent domestic (receipts at Stanfield). For 2003, the ratio for the actual molecules delivered on GTN is approximately 8 percent domestic and 92 percent Canadian.

Contracted capacity

Table 7.5 below shows the major receipt points along GTN's system.

Table 7.5 Capacity at Major Receipt Points on GTN Pipeline

Location	Receipt Point Long-Term Firm Capacity (MDth/day)
Kingsgate	2,900
Stanfield	200
Total	*3,100*

Shippers, Contracts, and Delivery Points

Table 7.6 below shows the top shippers on GTN's system based on contracted demand.

Table 7.6 Top Ten Major Shippers, on GTN Pipeline, Contracted Delivery (Maximum Daily Quantity), and Primary Delivery Points

Company	Maximum Daily Quantity (MDth/d)	Primary Delivery Points
Pacific Gas and Electric Company	610	Malin
EnCana	166	Stanfield and Malin
Calpine	162	Malin and Hermiston
Avista	161	Various
Duke	136	Stanfield, Hermiston and Malin
Sierra Pacific Power	135	Stanfield and Malin
Pan-Alberta Gas	100	Stanfield
NW Natural	98	Spokane and Stanfield
Mirant	80	Stanfield and Malin
PPM Energy	66	Malin
Others	881	Various
Total Existing Long-Term Firm Contracts	*2,595*	

Subscribed capacity and actual capacity factor

Approximately 95.5 percent of GTN's system capacity is fully subscribed. GTN's actual capacity factor was approximately 69 percent in 2003.

Major physical constraint points

GTN has completed preliminary route feasibility studies for major pipeline laterals to serve growing market requirements, particularly for power generation, along the I-5 corridor in both Washington and Oregon. Either of the laterals could be in service within three years of establishing commitments from customers, or as early as mid 2007. While market growth will dictate the exact timeline, GTN expects to have them in service by the end of the decade. GTN has also completed study work on a potential future expansion of its mainline system. As with the lateral projects, market growth will dictate the exact timing of the expansion.

Expansion into new production areas

For the past two years GTN has been actively involved with a consortium of U.S. and Canadian pipeline companies in an effort to engage the Prudhoe Bay producers in a discussion around the commercial viability of a pipeline from the Alaska North Slope to Alberta, Canada. As a result of these discussions, GTN has developed plans to expand its mainline from the Canadian border near Kingsgate to the California border near Malin, Oregon. These expansion plans range in size from 100 MDth/d to 1,000 MDth/d of incremental capacity. These expansion plans will also accommodate new supplies from the MacKenzie River Delta.

GTN also recently concluded an open contract season for its North Baja Pipeline located in Southern California. The open season targeted liquified natural gas developers and resulted in seven requests totaling 5.5 Bcf/d to bring LNG onshore to Southwestern U.S. and Mexican markets by 2007.

Changes in storage capability

GTN has not changed its storage profile over the last three years.

Recent capacity changes

Approximately 211 MDth/d of annual service plus an additional 20,380 Dth/d of winter only service was added from Kingsgate, B.C., to Malin, Oregon, through GTN's 2002 Mainline Expansion. The expansion was placed in service on November 1, 2002. The cost of this project was approximately $129 million.

Upcoming changes

GTN may need an expansion in the next five years to provide mainline support for the two lateral projects previously described. GTN further expects to expand its mainline to provide DEGT access to the MacKenzie Delta region of Canada, Alaska or other Arctic gas supply within the decade.

Duke Energy Gas Transmission West (DEGT West)

The majority of information contained in this section on the DEGT West Pipeline[72] originated from the pipeline company itself via a survey conducted by the OTED Energy Policy Division and its contractors. The company was asked to provide information about the impact of new pipelines on its business, the ratio of gas from Canada versus the Rocky Mountains, major receipt points, largest shippers, capacity utilization, constraints, expansion plans, permitting process, storage and long-term plans.

System Overview

Duke Energy Gas Transmission West owns and operates a natural gas gathering, processing and transmission system in British Columbia, the Yukon and Northwest Territories. Through its subsidiary, Westcoast Gas Services Inc. (WGSI), DEGT West also manages and operates other gathering and processing assets in British Columbia. Through another subsidiary, Westcoast Transmission Company (Alberta) Ltd., DEGT West owns transmission facilities in Alberta that are connected to its federally regulated system.

The gathering, processing and transmission system is managed through three business units: the Field Services Division, which manages all National Energy Board of Canada (NEB) regulated gathering and processing facilities; the Pipeline Division, which manages all NEB and Alberta Energy and Utilities Board (AEUB) regulated transmission facilities; and WGSI, which manages the provincially regulated gathering and processing facilities in British Columbia.

The Field Services Division operates more than 2,800 kilometers of NEB regulated gathering lines and five processing plants that provide access to thousands of gas wells in the Western Canadian Sedimentary Basin -- an area that contains some of the most productive gas wells in North America.

DEGT West's plants have a gas processing capacity of approximately 1.8 Bcf/day and an approximate 67 percent market share of the British Columbia portion of the Western Canada Sedimentary Basin. Much of the gas found in Northern British Columbia contains high levels of sulphur, in the form of hydrogen sulphide. Processing this "sour" gas is a complex process that has resulted in the DEGT West system having fewer plants (of significantly larger size), which maximize economies of scale and minimize environmental impact. In contrast, the gas found in Alberta is largely "sweet" gas (low in sulphur), which lends itself to processing facilities that are less complex and generally of smaller capacity. As a result, Alberta gas processing is characterized by numerous smaller gas processing plants.

The Pipeline Division is the major transporter of natural gas in British Columbia. With 2,800 kilometers of transmission pipeline, the Pipeline Division facilities transport natural gas for suppliers to markets in western Canada and the U.S. Pacific Northwest. Approximately 53 percent of the annual throughput volumes for 2002 were exported

[72] Duke Energy Gas Transmission West (DEGT) was formerly called Westcoast Pipeline.

through Huntington for the U.S. Pacific Northwest markets. The remainder was delivered to markets in Canada and to a spur on the pipeline, which delivers gas to the Sumas Energy generating facility, petroleum refineries, and other industrial consumers just over the U.S. border.

The pipeline system is separated into three regions (North, Central, and South) for operating purposes. For tolling purposes the pipeline is divided into two segments -- transportation north and transportation south. In the Northern region, Alliance Pipeline takes delivery of gas from the DEGT West pipeline system at Gordondale, via the Westcoast (Alberta) system. The Southern transportation system travels through some of British Columbia's most rugged terrain to bring gas from Station 2 to domestic and export markets in the U.S. Pacific Northwest.

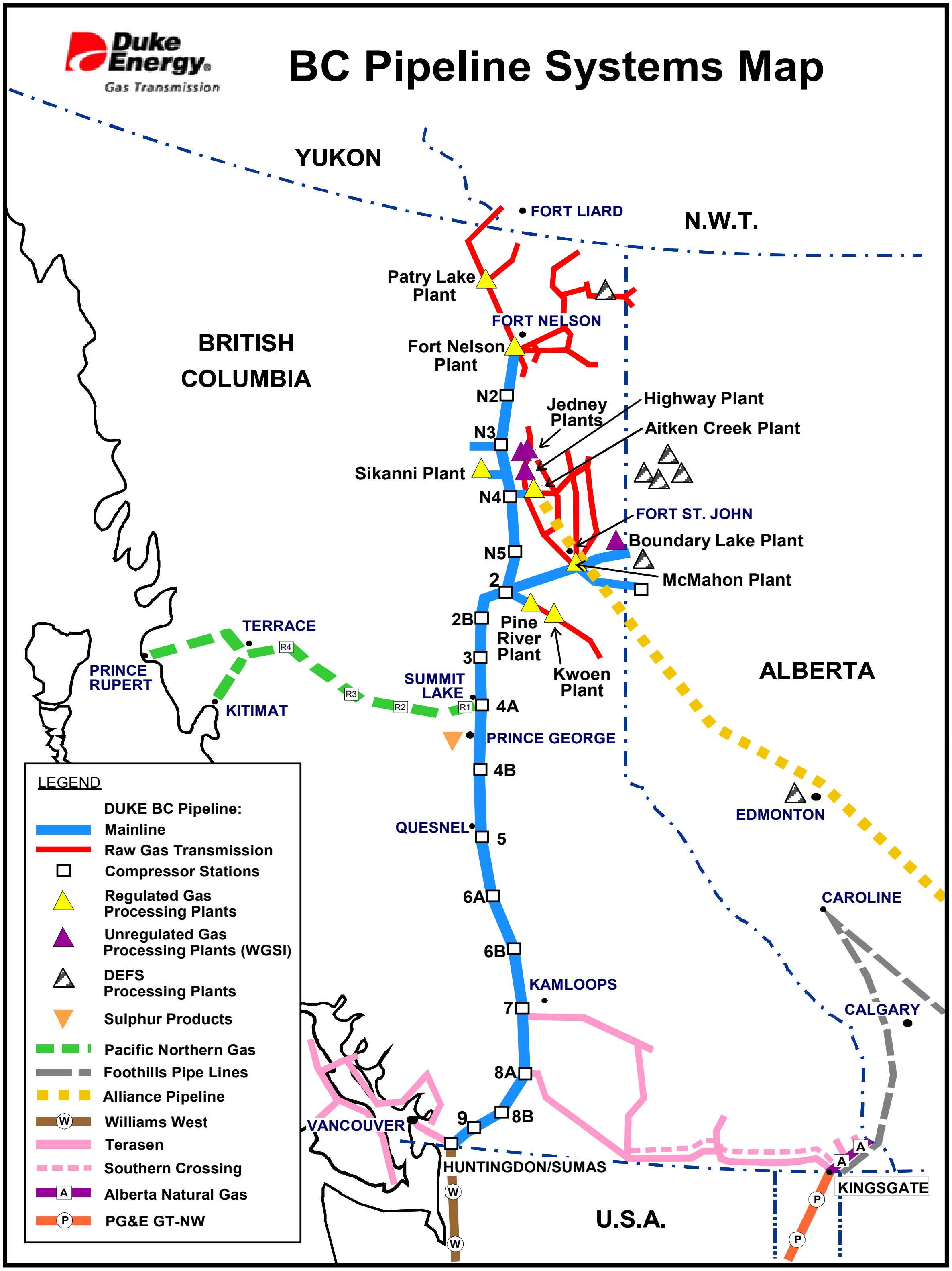

Figure 7.6: DEGT West System Map

Note: Since this map was created the name of PG&E Pipeline has changed to National Energy & Gas Transmission Gas Transmission Northwest (GTN) and Williams West Pipeline has changed its name to Northwest Pipeline.

Canadian/domestic split gas deliveries

The contract split between domestic (British Columbia) gas deliveries versus export deliveries (United States and Alberta) from the DEGT system is 37 percent to markets in British Columbia and 63 percent to export markets.

Contracted capacity at major receipt points

DEGT delivers gas to downstream pipelines, and therefore provides the contractual capacity at major delivery points along the system. The delivery capacity effective November 1, 2003, is provided in the following table.

Table 7.7 below shows the major receipt points along DEGT's system.

Table 7.7: Capacity at Major Receipt Points – DEGT Pipeline

	Total Capacity MMcf/d
Huntington/Sumas	1702
T-South -- Inland and Kingsvale	171
T-South -- Pacific Northern Gas	115
T-North -- Alliance/Gordondale	182
Total	2170

Shippers, Contracts, and Delivery Points

When contracting for transportation service on DEGT's system, shippers contract separately on the T-North system (north of compressor station #2) and the T-South system (south of station #2 to Huntington/Sumas). As illustrated below, the shipper groups on each pipeline segment differ.

On its T-North system, DEGT delivers gas to communities along its mainline, however, the majority of its deliveries are to Alliance Pipeline or to the NOVA system in Alberta via the ABC Gordondale Interconnect. It is important to note that the interconnection with NOVA at Gordondale is a bi-directional line. This feature allows gas to flow either eastbound into Alberta or westbound into British Columbia as the market conditions require. As illustrated in the table below, T-North shippers are composed primarily of natural gas producing companies. Additionally, there are less than 10 firm export shippers. Table 7.8 shows the top shippers on DEGT's T-North system based on contracted demand.

Table 7.8: Top Ten Major Shippers, Contracted Delivery (Maximum Daily Quantity), and Primary Delivery Points – DEGT T-North

Transportation North - Export Points		
Company	**Delivery Points**	**Max Daily Quantity (MMcf/day)**
Alliance Pipeline Ltd.	Alliance Boundary/Lake Interconnect	70
CanWest Gas Supply Inc.	ABC Gordondale Interconnect	27
Unocal Canada Limited	ABC Gordondale Interconnect	10
Dominion Exploration Canada	ABC Gordondale Interconnect	8
Anadarko Canada Corporation	ABC Gordondale Interconnect	7
ProGas Limited	ABC Gordondale Interconnect	5
Devon Canada Corporation	ABC Gordondale Interconnect	3
Canadian Natural Resources	ABC Gordondale Interconnect	1
Total		**130**

T-South shippers represent a combination of end use customers, producing companies and natural gas marketers. Table 7.9 shows the top shippers on DEGT's T-South system based on contracted demand. Delivery Points are T-South Inland (TSIND), T-South Lower Mainland (TSLM), T-South Export (TSEXP), and T-South Pacific Northern Gas (TSPNG).

Table 7.9: Top Ten Major Shippers, Contracted Delivery (Maximum Daily Quantity), and Primary Delivery Points – DEGT T-South

Transportation South		
Company	**Delivery Points**	**Maximum Daily Quantity (MMcf/day)**
Terasen Gas Inc.	TSIND, TSLM, TSEXP	535
Duke Energy Trading & Marketing	TSEXP	161
Canadian Natural Resources	TSEXP	75
Talisman Energy Canada	TSEXP	68
ExxonMobil Canada Energy	TSEXP	65
Anadarko Canada Corporation	TSEXP	62
CanWest Gas Supply Inc.	TSEXP	61
Methanex Corporation	TSPNG	58
Devon Canada Corporation	TSEXP	58
Northwest Natural Gas Company	TSEXP	56
All Other Shippers		765
Uncontracted Capacity		24
Total		**1988**

Subscribed capacity and actual capacity factor

As of November 1, 2003, approximately 96 percent of total capacity is subscribed. Because DEGT serves temperature sensitive markets in British Columbia and the Pacific Northwest, the load factor varies depending on the time of year. For example, for the year 2002, the annual load factor for the Southern mainline based on average daily flows was approximately 77 percent. For the 2002/2003 winter season, the load factor was approximately 87 percent. The maximum load factor achieved over the last year was on Dec. 18, 2002, when the Southern mainline operated at 96 percent of full capacity.

Major physical constraint points

DEGT is currently expanding its T-South pipeline system and this expansion will be placed in service November 1, 2003. The expansion, which originally contemplated the addition of 200 MMcf/d of incremental capacity, was reduced to 85 MMcf/d to reflect near-term changes in market conditions. While the project has been reduced, the National Energy Board has given approval for the full 200 MMcf/d expansion. Given this approval and should market conditions change such that additional incremental capacity is required, DEGT is well positioned to increase the capacity of T-South by an additional 115 MMcf/d. DEGT expects new capacity could be constructed in a timely manner since regulatory approvals are already in place. Therefore this increment of expansion can occur in a period of time that is much shorter than the original 30 months.

Other expansion plans

The DEGT system is not currently constrained. However, the company monitors the needs of markets and customers for incremental pipeline transport capacity. To the extent that market growth generates a requirement for additional capacity DEGT will conduct a contract open season to determine the interest of customers. This method aims to ensure that the system is not over built and transportation tolls are kept as low as possible.

Expansion into new production areas

DEGT plans to expand as producers capture new gas supplies from the Western Canadian Sedimentary Basin (WCSB) including Northeast British Columbia, the Southern Yukon and the Southern Northwest Territories. DEGT British Columbia will also expand its pipeline systems and processing facilities as supplies from interior basins and offshore British Columbia become available. These supplies are not expected to come on stream until after 2010. Duke Energy expects that both McKenzie Delta and Alaska gas will be required to meet future North American gas demands.

Changes in storage capability

DEGT currently does not own or operate storage facilities in British Columbia or the Pacific Northwest. DEGT is interested in developing future storage infrastructure in the Pacific Northwest but has no definitive plans at this point.

Recent capacity changes

Since January 2001, DEGT has had two major expansions of its pipeline system.

- <u>T-North Fort Nelson Expansion</u> – This expansion, totaling 43 MMcf/d of incremental capacity, was designed to connect growing supplies in the Fort Nelson, B.C. area to DEGT's mainline transmission system and to move this gas to Compressor Station

#2, the supply basin trading hub in British Columbia. The expansion went into service on November 1, 2002. The time period from the end of the open season to the in-service date was 15 months. The cost of this expansion was approximately $1.5 million Canadian.

- T-South Expansion – This expansion, which just came into service at the end of 2003, was in response to demands from the end use market. The expansion, which originally contemplated the addition of 200 MMcf/d of incremental capacity, was reduced to 85 MMcf/d to reflect near term changes in market conditions.

  The expansion consists of new compression at Station #8B and new compressor wheels at Station #9. The cost of this expansion is approximately $50 million Canadian.

Upcoming changes

DEGT anticipates that end use markets in British Columbia and the Pacific Northwest will grow on average by approximately 2.5 percent per year. The primary driver behind this growth is expected to arise from incremental gas-fired generation in the region.

As a common carrier, DEGT will respond to this growth with expansion of capacity and as the market requires. As previously noted, DEGT currently has NEB approval to add 200 MMcf/d of pipeline capacity to its southern mainline system (T-South). Given that it will only be adding 85 MMcf/d for November 1, 2003, the groundwork for constructing an incremental 115 MMcf/d has already been completed.

Natural Gas Storage

As Pipeline capacity demand in the Western United States continues to expand, the need for underground storage facilities to support this growth also is being addressed. In the Western region of the United States, more than 2,690 MMcf/d of proposed new pipeline capacity is related to development of storage infrastructure during 2003-2005.[73]

The Jackson Prairie Storage Facility located near Chehalis, Washington, is the third largest natural gas storage field in the world. It is located on the Northwest Pipeline system, and is co-owned in equal shares between the Northwest Pipeline Company, Puget Sound Energy and Avista Corporation. The Mist storage facility in Northwestern Oregon is owned by Northwest Natural.

These storage facilities are primarily used for seasonal storage to increase peak day deliverability. Gas is injected during off-peak periods and retrieved during the peak winter heating season. Refill begins in spring and continues through September, when 90-100 percent of capacity is usually achieved. As much as half of the gas used by consumers on a cold winter day comes from storage fields.

[73] Source: EIA, Office of Oil and Gas, *Expansion and Change on the U.S. Natural Gas Pipeline Network*, 2002.

Jackson Prairie has a daily withdrawal capacity of 874 MDth. Working gas capacity is 18,300 MDth. Puget Sound Energy is the FERC-certified operator of Jackson Prairie. Northwest Pipeline is responsible for the scheduling, metering and accounting activities that are associated with the Jackson Prairie facilities. Puget and Avista use their portions of the stored gas to provide peak day deliverability for their core customers. Unneeded portions may be leased to third parties on an interim basis. Northwest Pipeline does not market natural gas -- its portion of the facility is either used to provide balancing gas or leased to shippers (Puget has arrangements for 15-20 percent of Northwest's share of Jackson Prairie).

The location of major storage facilities close to end-use customers allows storage to substitute for pipeline capacity in meeting peak demand days. Because gas can be shipped to storage facilities west of the Cascades during the summer when interstate pipelines operate at less than 100 percent capacity, these pipelines need not be sized to meet downstream peak demands. This means that the value of natural gas storage to the Northwest is not derived solely from winter/summer price differentials, but also from savings from avoided pipeline upgrades.

As the demand for natural gas for electricity generation increases, there may be less delivery capacity available during off-peak periods for injection into storage facilities, and the gas that is available may be more costly. If natural gas prices become more sensitive to the price of electricity, this may mean that natural gas will no longer be significantly cheaper during summer months. The risk management strategies historically used by local gas distribution utilities may need to be revised in order to minimize the cost of gas service to traditional core-market customers as gas-fired electric generation is added to regional natural gas demand.

Table 7.10 Natural Gas Storage Facilities Available to the Pacific Northwest

Name	Withdrawal Capacity (MMcf/day)	Pipeline	Location
Jackson Prairie	850	NWP	Centralia, WA
Clay Basin*	450	NWP	Northeast Utah
Plymouth LNG	300	NWP	Columbia Gorge area, WA
Mist	190	NWP	Northwest of Portland, OR
Gasco LNG	120	NWP	Near Portland, OR
Newport LNG	60	NWP	Newport, OR
Columbia Hills	(Proposed)	NWP and GTN	

* The Clay Basin storage facility is east of the Kemmerer Corridor, which is a potential constraint point for gas being delivered to the Pacific Northwest.

Section 8: Summary

In this report the Energy Policy Office has updated and broadened its 2001 report *Convergence: Natural Gas and Electricity in Washington*. In the 2001 report we examined the rapid and large ongoing (and projected) increase in natural gas consumption by the power generation sector, and the potential consequences of these changes on gas usage and infrastructure. In this report we expanded our analysis and examined the entire natural gas market both regionally and nationally. We focused our efforts on the gas price volatility during 2000-2003, with emphasis on how regional and national supply, demand and infrastructure issues played into the gas price volatility. Our analysis leads us to conclude, as have many others, that the U.S. natural gas market has fundamentally changed over the last six years moving from a market with excess gas production capacity to one with a very tight balance between gas supply and demand. The topical highlights of the report are briefly summarized below:

Recent History

- Natural gas prices were low during the 1990s, generally around $2.5/MMBtu (wellhead price in 2002 dollars), which encouraged consumption.
- The 2000-01 West Coast energy crisis saw gas prices increase dramatically, reaching $17/MMBtu at the Sumas gas hub in January 2001.
- Regional and national prices dropped to near historical levels during late 2001, primarily the result of a national recession, fuel switching by some industrial users, more hydropower generation, and a mild winter.
- Prices began to rise in late 2002, and skyrocketed by the spring of 2003. A cold winter and decreasing production in Canada and the United States were the primary factors.
- Average retail natural gas prices for residential and commercial consumers in Washington State have almost doubled since early 1999.
- Concern over high gas prices and a production shortfall, spurred U.S. Department of Energy Secretary Spencer Abraham to ask the National Petroleum Council to undertake a new study on natural gas in the United States and North America. A draft of this study was released in September of 2003.

Supply

- North America has a substantial gas resource, with proved reserves of approximately 280 Tcf and total resources of approximately 2,100 Tcf. Approximately 1,400 Tcf of natural gas has been consumed in North America.
- Much of the remaining resource is unconventional or very remote and consequently is more costly and risky to develop. A significant amount is located in restricted access areas, where future development is uncertain
- U.S. natural gas production has not kept pace with U.S. demand growth over the last 10 years despite increasing exploration and drilling activity.

- Until 2001 the supply gap was minimal due to favorable weather, abundant hydropower generation, and strong growth in gas imports from Canada.
- Natural gas forecasts prepared in 1999 by the National Petroleum Council (NPC) and in 2001 by the Energy Information Administration (EIA) were overly optimistic about supply (and demand) growth through 2020. These forecasts had the unfortunate effect of encouraging additional natural gas usage.
- More recent natural gas forecasts by the NPC (2003) and the EIA (2004) contain significant downward revisions in future resource availability, gas production, and gas demand. The NPC forecast revised the U.S. production for 2015 downward by 5.5 Tcf (per year), while the EIA revised its forecast U.S. production in 2015 downward by 4.6 Tcf.
- Canadian production is expected to be flat or grow minimally over the next several years, and may begin to decline after 2010. Imports from Canada will no longer be able to cover the complete U.S. production shortfall.
- Mexican gas supply is lagging internal gas demand, necessitating increasing imports from the United States.
- Arctic gas resources are cost competitive in the current market ($5/MMBtu) and are likely to be developed during the next 10 years.
- LNG imports are currently cost competitive and are expected to account for as much as 10 percent of U.S. supply by 2010.
- Washington State does not produce natural gas and primarily imports gas from Canada and the Rocky Mountain regions.
- Washington State is situated relatively near the Rocky Mountain gas supply basins, which is one of the few areas where U.S. production is expected to grow.
- New pipeline connections mean Washington State will have to compete with the Midwest and California for natural gas from the Rocky Mountain region.
- Washington State is located relatively close to the Canadian gas hubs where future Arctic natural gas could be delivered.

Demand

- North American natural gas demand increased by approximately 25 percent, or slightly more than 4 Tcf/year, during the 1990s. Demand in Washington State increased even more rapidly during this time period: up by more than 50 percent, or about 100 Bcf /year.
- Much of the demand growth was in the electric power generation sector where nationally consumption increased by approximately 60 percent or 2 Tcf/year.
- Industrial consumption also increased rapidly during the 1990s, about 1.2 Tcf/yr nationally, equivalent to approximately 17 percent. Much of this growth was due to expansion of combined heat and power generation.
- During the 1990s regional gas price differentials diminished as a continental gas market emerged. Shortages and high prices in one region now significantly impact other regions.

- The 1999 NPC and 2001 EIA demand (and supply) forecasts were extremely bullish, forecasting annual U.S. demand exceeding 30 Tcf/year by 2010 to 2015.
- The 2003 NPC report reduced the forecast U.S. demand for 2015 by just over 4 Tcf/year.
- At the old market prices, natural gas demand exceeds available supply, making higher prices necessary to bring demand and supply back into equilibrium.
- Higher prices have resulted in industrial demand destruction and limited fuel switching.
- Washington State households, businesses, and industry continue to become more energy efficient: Washington's energy consumption per constant dollar of gross state product declined by 40 percent form 1980 to 2000.
- Gas demand growth forecasts for the Pacific Northwest electricity sector over the next 10 years have been scaled back: Annual gas forecast demand growth in the electric generation sector was reduced from 9.2 to 4.0 percent. This reduction was primarily due to the permanent loss of most of the Northwest aluminum industry – a large consumer of electricity.
- Population growth and the increased emphasis on natural gas for electric power generation are the underlying causes of regional natural gas demand growth.
- Efficiency and conservation are the most important near-term factors for reducing natural gas demand, and upward price pressure.
- Fuel switching in the industrial sector can reduce demand in the very near term: days to weeks time frame.
- Renewable power generation is an important mid- to long-term factor for reducing natural gas demand.

Natural Gas Price Volatility

- Natural gas price volatility will remain as long as supply and demand remain in tight balance.
- With a tight supply-demand balance the severity of seasonal weather (cold winter, hot summer) has the largest impact on natural gas price and volatility. Economic activity and gas storage levels also impact price and volatility.
- High gas prices lead to demand destruction in the industrial sector, which has significant economic consequences.
- Price forecasts made during the 1990s and through 2001 were extremely optimistic about the potential for a small increase in gas price to bring significant quantities of new gas supply to the market
- In the past, the fuel switching abilities of many businesses helped dampen price volatility. Low gas prices during the 1990s and more stringent environmental regulations have reduced the fuel-switching potential at national and regional levels.
- LNG imports, Arctic gas, efficiency and conservation programs, and renewable energy resources, all have the potential to dampen price volatility.
- Natural gas storage helps utilities and power generators meet variations in demand and dampen price volatility. The increasing use of natural gas as a fuel for power generation will necessitate changes in gas storage volumes and patterns.

Infrastructure

- Due to recent expansions, the pipeline system in the Pacific Northwest is fully integrated into a North American pipeline system and as a result, a North American gas market.
- Much of the recent capacity additions in the western United States are directed towards supplying California and the Midwest.
- The fraction of natural gas coming to the Northwest from the Rockies is increasing relative to that from Canada.
- Although storage capacity has increased in the Northwest, reliance on storage has increased more so, largely due to the use of storage for hedging against price instability.

Section 9: Natural Gas Policy Issues and Recommendations

Natural gas markets in the United States and the Northwest have been changing, as described in this report. Growing demand for natural gas along with constrained supplies suggest that future natural gas prices will be higher and more volatile. This situation requires a reexamination of natural gas energy policy nationally and in the Pacific Northwest. In the first portion of this section we summarize natural gas policy proposals and discussion at a national level. In the second portion we outline issues, and options for consideration at the state level. Our intent is to begin to develop a framework for discussion that ultimately will result in a more complete natural gas energy policy in Washington.

National Policy Issues Framed in Recent Reports

The conditions that spurred the growth in gas consumption during the 1990s and encouraged the high growth forecasts for the 2000-2020 period, the apparent abundance of natural gas and low prices, appear to have changed dramatically over the last several years. The recent gas market forecasts paint a significantly different picture of the future; one where supply and demand remain in tight balance and prices are significantly higher than historical norms.

In this context U.S. policy makers are now considering a variety of long-term supply and demand strategies to address concerns about high gas prices and price volatility. The most detailed recent national policy review was performed by the National Petroleum Council and is summarized below. Many of these recommendations are controversial and while CTED does not necessarily endorse all of these proposals, we believe it is important for readers to understand the natural gas policy proposals that are being discussed at the national level.

Increasing Efficiency and Demand Flexibility: Efficiency and conservation by natural gas consumers provides one of the best near-term options for reducing natural gas demand and price volatility.

1. Public education: Enhance public education programs for energy conservation, efficiency and weatherization. Identify best practices and encourage adoption of these practices nationwide.
2. Review and upgrade efficiency standards: Review and compare efficiency standards for buildings and appliances. Upgrade in a timely and cost-effective manner.
3. Provide clearer market price signals to consumers to facilitate efficient gas use.
4. Provide industrial cogeneration facilities with access to markets.
5. Increase industrial and power generation capability to utilize alternate fuels. Remove discrimination against alternative fuels that can meet performance standards.
6. Provide certainty of air quality regulations, especially under New Source Review, to create a clear investment setting for industrial consumers and power generators.
7. Consider the costs and benefits of fuel switching capability when developing integrated resource plans (IRPs).

Increasing Supply Diversity: Traditional North American gas resources appear unable to meet long-term demand growth expectations. New sources of natural gas, such as Arctic gas and LNG, will be needed to help close the supply gap and meet anticipated growing demand.

1. Enact enabling legislation for an Alaska pipeline in 2004. Passage of this legislation would provide project certainty and ensure deliveries begin in 2013-14. The legislation should incorporate adequate risk mitigation for developers, while minimizing potential cost exposure for taxpayers.
2. LNG development should be actively encouraged. Permitting activities for the development of LNG offloading terminals should be streamlined and timely; regulatory authority should be clarified. LNG safety should be reviewed and updated if necessary; public education on LNG should be enhanced.
3. Increase access and reduce permitting impediments to development of Lower 48 resource development. An increasing fraction of our future natural gas resource will be located on federal lands that are excluded from development or have highly restricted access.

Sustaining and Enhancing the Natural Gas Infrastructure: Additional infrastructure will be required to meet the future needs of the natural gas market.

1. Federal and state regulators should provide regulatory certainty by maintaining a consistent cost recovery and contracting environment.
2. Complete permit review of major infrastructure projects within one year. A joint agency review process should be developed
3. Barriers to establishing long-term contracts for customers should be examined.
4. FERC and public utility commissions should keep apace of changing infrastructure needs created by the new gas suppliers from the Arctic and LNG.
5. Regulators should evaluate and encourage research into more efficient and less expensive infrastructure options.

Promoting Efficiency in the Natural Gas Markets: North American natural gas markets are relatively efficient, but could be improved.

1. The EIA should improve the monthly and annual natural gas data collection and reporting process.
2. The EIA's weekly storage data collection reporting should be expanded so it more adequately reflects actual gas storage volumes.
3. EIA should reduce the time lag in their reported data series by one month.
4. Voluntarily reporting services for natural gas transactions should be examined to guarantee accuracy and prevent manipulation.
5. The natural gas resource assessment methodologies used by various government agencies and businesses should be periodically examined and updated. Modeling information and data should be made more publicly available.

State Policy Issues, Opportunities and Questions

The State of Washington's long-term policy goal is to ensure a reliable supply of natural gas for consumers, at reasonable prices, with minimal price volatility, and with acceptable environmental consequences. This section outlines policy opportunities for reducing natural gas prices and price volatility in Washington State. These opportunities cover: 1. Supply diversity, 2. Demand reduction, 3. Infrastructure improvements, 4. Measures to reduce price volatility. The issues and opportunities presented here provide an initial framework for further development of a natural gas energy policy in Washington.

Supply Diversity: Diversifying the source of natural gas on the West Coast is one approach for mitigating the problems with natural gas supply. Two new gas resources that offer good opportunities are presented below.

1. *Arctic Natural Gas*: Resources in Northern Canada and Alaska have the potential to contribute over 6 Bcf per day to North American supply at a sizable net economic benefit to the nation.[74] Development of the Arctic resources would provide more natural gas to regional gas trading hubs thus potentially helping regional consumers. In addition, the development of these resources could provide a sizable regional benefit during the construction of the pipeline.

2. *Liquefied Natural Gas (LNG)*: The price for LNG delivery has fallen dramatically over the last 20 years. Activating and upgrading the four existing LNG receiving terminals and adding four new receiving terminals over the next decade would provide approximately 6 Bcf per day of additional supply.

   Development of LNG delivery facilities in Southern California and Baja Mexico should reduce competition for the limited natural gas resources coming from Western Canada and the Rocky Mountain basins. Over the longer-term, Canadian gas imports will decline making it likely that Washington State will have to consider development of a local LNG delivery facility. Stakeholder support for development of a regional LNG facility should be evaluated in the near future.

Demand Reduction: Slowing demand growth can help mitigate high gas prices and volatility. We have identified three broad areas for reducing natural gas demand.

1. *Conservation and energy efficiency*: Increasing the energy efficiency of natural gas consumption is an effective way to both reduce demand for natural gas and the costs for natural gas supply and capacity development. The Northwest has a long history of using electricity efficiency improvements to reduce electricity system

[74] An economic analysis by the National Commission on Energy Policy (October 2003) stated that accessing Alaska natural gas would provide net benefits of 4.5 billion dollars per year to gas consumers. The net benefits would be higher if the avoided losses of industrial jobs due to high gas prices were included.

resource development costs.[75] While there have been investments in natural gas energy efficiency, a level of effort comparable to electricity has not occurred. We offer the following options for natural gas energy efficiency efforts.

- *Increase and maintain investments in natural gas energy efficiency and demand response programs.* Raising tariff riders and program targets to reflect higher natural gas costs and constrained supplies could be considered.

  Natural gas utilities in Washington are increasing their investments in energy efficiency, descriptions of which can be found in Appendix D.

- *Maintain and strengthen electricity energy efficiency programs to reduce load growth.* Electricity energy efficiency programs have successfully reduced the demand for electricity generation. In the absence of these programs, much of the new generation capacity would likely have been provided by natural gas-fired power plants, which would have significantly increased regional natural gas demand.

- *Develop public awareness, information and education campaigns on energy efficiency and conservation.* Public awareness campaigns reduce consumption when people perceive a clear need and individuals have the ability to take action. Water conservation and recycling efforts are good examples of the potential effectiveness of public awareness campaigns. The experience in California during the 2001 West Coast Energy Crisis illustrates that a broad energy efficiency and conservation campaign can produce significant energy reductions.

- *Strengthen federal, regional and state cooperation.* Markets stretch across local and state boundaries. In order to change markets so that energy efficient products, services and practices become more common, federal, regional, and state collaboration is necessary. This is often referred to as market transformation. At the federal level, the Energy Star and Rebuild America Programs are examples of initiatives that could be vehicles for expanded federal, regional, state, and local collaboration for improving natural gas energy efficiency.

- *Provide public sector leadership at the state (and local) level.* Public institutions can lead the way in reducing natural gas consumption. In January 2001, during the West Coast Energy Crisis, Gov. Gary Locke issued an executive order asking all state and local government agencies to take all measures necessary to reduce electricity and natural gas energy use by 10 percent.[76] These mechanisms could be reviewed to see if they are being used and followed, and modified if appropriate.

[75] The Northwest Power and Conservation Council reports regional energy savings since 1980 totaling more than 2,600 average megawatts from Bonneville Power Administration/utility programs, state energy codes and federal efficiency standards.

[76] The executive order included suggestions for reducing energy use. State executive agencies showed a reduction in electricity use of 8.9 percent for the quarter ending in September 2003 relative to the 2000 base period, but natural gas consumption increased 2.7 percent over the same time period.

Consideration should be given to expanding these opportunities to other public institutions.

- *Improve and maintain appliance efficiency standards and building codes.* Appliance efficiency standards and building codes have been two of the most effective methods for widespread improvements in energy efficiency. For appliance efficiency relative to natural gas, Washington State could encourage DOE to accelerate its standards rulemakings for residential heating equipment and commercial air conditioning equipment.

  State energy codes for buildings in Washington have steadily improved over the years. Future efforts to improve building energy codes should account for improvements in building technologies and techniques as well as higher natural gas costs. These changes make higher levels of energy efficiency cost effective.

- *Encourage integrated natural gas resource least cost planning and consider combined electricity/gas planning.* The Washington Utilities and Transportation Commission requires least cost planning for all utilities. These plans are required to incorporate an assessment of technically feasible improvements in the efficient use of natural gas.[77] Puget Sound Energy recently used a least cost planning process to identify the targets for its natural gas energy efficiency efforts. However, least cost planning has not been widely applied by utilities to identify cost-effective natural gas energy efficiency opportunities. Use of this planning process should be encouraged to promote cost-effective natural gas efficiency efforts.

  On a regional level, the Northwest Power and Conservation Council uses least cost planning principles to develop its five-year electric power plans for the region. No comparable regional planning process exists for natural gas. There may be value in having a broader regional effort that more fully considers gas system supply and capacity issues on a regional level.

- *Establish energy efficiency performance standards or public benefits funding.* A number of states have established efficiency performance standards or public benefits funding programs for their electric utilities. Under these laws, electric utilities are required to increase the efficiency of their generation and/or the way their customers use electricity. They usually do this by funding programs that encourage more efficient end use of electricity. We should explore whether there would be any benefit in requiring natural gas utilities to do the same things.

2. *Development of renewable energy*

   Renewable energy resources such as wind turbines can cost-effectively displace the need for additional gas-fired electrical generation and thereby take pressure

[77] The commission is considering proposed rules related to least cost planning. The review will consider whether the rules provide the results they were originally intended to achieve and whether they are consistent with agency policies and advances in technology.

off gas prices. Recent reviews by the Union of Concerned Scientists (UCS, 2003a,b) and the American Council for an Energy-Efficient Economy (ACEEE, 2003) have evaluated the impact that development of renewable energy resources could have on natural gas demand.

Another advantage of renewable energy programs is that they can be developed in the near term (two to three years) and brought to the market faster than Arctic gas resources or LNG facilities. The Pacific Northwest should use the ACEEE analysis as a starting point and examine the costs and benefits of programs that promote efficiency and renewable energy sources.

Some policies to consider for promoting the development of renewable energy resources include:

- Establishing a Renewable Portfolio Standard;
- Inclusion of environmental externality valuation in the IRP process;
- Using futures natural gas prices in addition to EIA price forecasts during utility IRP development;[78]
- Setting government purchase goals for renewable energy.

3. *Combined heat and power resources*: Combined heat and power (CHP) facilities typically operate at higher overall thermal efficiency levels, producing both electricity and process heat from a single heat source. Their higher thermal efficiency means that CHP can lead to reduced natural gas demand. CHP facilities are located where the process heat (often steam) and the electricity are used.

   A number of policy and regulatory efforts could be considered to promote additional development of CHP in the Pacific Northwest. These include:

   - Fair and reasonable interconnection standards for CHP;
   - Industry and utility joint partnering in CHP projects;
   - Consideration of CHP's environmental benefits in the utility IRP process;
   - Environmental credit to CHP (due to its greater thermal efficiency, etc.);
   - Production Tax Credit for net environmental benefits and fuel savings from CHP projects.

Natural Gas Infrastructure Improvements: The policy pathway for natural gas infrastructure improvements is not as clearly defined as it is for supply and demand policy options. Therefore we are presenting the section on natural gas infrastructure improvements as a series of questions to raise issues we believe are important.

1. Should the state support a greater level of instate natural gas storage capacity and use it as a more cost-effective means than additional pipelines to ensure supply reliability and manage price volatility?

[78] The EIA has consistently underestimated gas prices during 1999-2003, which may lead to an underestimation of the true costs for gas-fired electricity generation.

2. Are there any concerns about the open season process? Is it working? Does it provide a strong enough signal to pipeline companies about how to develop? Are open seasons held frequently enough? Are they fair?
3. The energy sector may not be able to acquire all the financing it needs for critical infrastructure investments. Are there ways the state can help improve access to capital for the energy sector?
4. Should the government authorize construction of enough infrastructure to ensure there is never a supply shortfall or are consumers willing to accept a minimal level of risk of shortfalls to avoid higher costs?
5. Does the government (federal/state/local) permitting process operate effectively to ensure needed facilities can receive permits in a timely manner?

Management Actions to Reduce Price Volatility: We have identified three options that energy regulators and industries might pursue to reduce natural gas price volatility.

1. Market Information

   Efforts should be undertaken at the regional level to expand and enhance availability and resources for natural gas market information. Energy markets can be distorted by late or inaccurate storage, supply or production information.[79] Timeliness and accuracy of reported sales by marketers, and production information from energy businesses should also be enhanced.

2. Portfolio Management: Financial and physical hedging

   The current deregulated electricity and natural gas markets exhibit substantially more volatility than their regulated predecessors and therefore open local distribution companies, marketers, and eventually consumers, to substantial financial risk. To reduce the financial risk LDCs and others practice portfolio management (PM), which is a technique for diversifying an organization's resource mix. See Appendix E for a brief description of some PM techniques. LDCs should be encouraged to learn more about the evolving PM strategies of financial and physical hedging strategies that are used to mitigate price volatility.[80] Regulators should encourage LDCs to use PM, and possibly establish reward criteria for those that are well managed and beat gas market indices.

3. Natural Gas Cost Recovery

   The four regulated natural gas utilities in Washington State recover their costs for purchasing natural gas for their customers through an annual Purchased Gas Adjustment (PGA) filing with the Washington Utilities and Transportation Commission. The PGA is intended to pass actual utility costs for acquiring natural gas to customers. The recent high and volatile wholesale prices have been largely passed on by the PGAs, to consumers resulting in very significant

[79] Nationally, the EIA has already taken steps to improve the quality and timeliness of the monthly storage and other natural gas information.

[80] Hedging techniques reduce risk, but at a cost premium if managed by third parties.

rate increases. It may be appropriate to revisit whether the PGA is an effective cost recovery mechanism and whether other options may better serve consumer and utility industry needs.

Some issues to consider include:

- Current natural gas market price risks and the extent Washington consumers are exposed to those risks;
- The ability of utilities to enter into financial arrangements and other risk mitigation strategies;
- The ability to provide consumers with stable, predictable natural gas prices;
- The ability to ensure that natural gas prices are reasonable and equitable for consumers.
- The ability to promote market efficiency by encouraging the use of tools and approaches that limit market volatility and allow the market to function effectively.

This is a complicated topic that needs to involve a variety of parties and further detailed analysis. This could be one of the most significant policy actions Washington can take to limit the exposure of Washington consumers to natural gas market risks.

Next Steps

The policy options we have explored above need to be further investigated in a public context. Other important and relevant options might have been missed in our review, and could be added to the items above. The CTED Energy Policy Division has recently joined with the state energy offices from western U.S. states and western Canadian provinces in an effort, directed by the Western Interstate Energy Board, to further evaluate long-term natural gas supply and demand. The Energy Policy Division will also begin a collaborative discussion with the energy industry, policy analysts, consumer advocates and other interested parties within Washington State. The results of the process will be a set of recommendations for the Washington State Natural Gas Energy Policy